# Issues in Focus

## Macroeconomic Forecasting with the Revised National Income and Product Accounts (NIPA)

### *The NIPA Comprehensive Revision*

Economic activity is a key determinant of growth in U.S. energy supply and demand. The derivation of the forecast of economic activity is therefore a critical step in developing the energy forecast presented in the *Annual Energy Outlook 2001* (*AEO2001*). In turn, the forecast of economic activity is rooted fundamentally in the historical data series maintained by a number of Federal Government agencies. The Bureau of Economic Analysis (BEA) in the U.S. Department of Commerce produces and maintains a series of accounts, with the NIPA being perhaps the most quotable and most often used [*17*]. The following discussion focuses on a major BEA revision of the NIPA historical source data and its implications for projections of energy demand.

The NIPA tables reflect historical data for U.S. gross domestic product (GDP) and its components, both on a nominal basis and in real terms. The derivation of the real activity data relies on a set of price indexes, also maintained by BEA, which show how prices have historically moved for each component of final demand and for the economy at large.

BEA revises the NIPA tables on a periodic basis, both from the perspective of conceptual changes in the way the accounts are prepared and to accommodate new and revised data. On occasion, BEA makes fundamental changes in the accounts. In 1996, NIPA shifted from using fixed-year price deflators to a chain-type deflator [*18*]. This had the effect of removing a substitution bias in the derivation of the measure of real GDP growth in the economy [*19*]. In 1999, BEA made a series of additional changes in the NIPA tables, some resulting in a fundamental change in measures of the historical rate of growth in the economy [*20*]. Table 4 compares the growth rates in GDP and its major components as previously computed and as revised.

In simply looking at the data before and after revision, there is an obvious change in historical rates of real GDP growth. One change is that the accounts are now rebased in 1996 dollars, as compared to 1992 dollars used previously. But this does not account for the difference in calculated growth rates, because the switch to chain-weighting eliminated this type of rebasing as a source of change in the historical growth rates [*21*]. Then where does the change in growth come from? Revisions to real GDP growth reflect two primary factors: (1) revisions to the current dollar components of GDP and (2) revisions to the prices used to estimate components of real GDP, plus revisions to the quantities used to estimate components of real GDP.

***Table 4. Historical revisions to growth rates of GDP and its major components, 1959-1998 (percent per year)***

| *Growth rate* | *Before revision* | *After revision* | *Difference* |
|---|---|---|---|
| ***Real GDP*** | ***3.2*** | ***3.4*** | ***0.2*** |
| *Consumption* | *3.4* | *3.6* | *0.2* |
| *Investment* | *4.2* | *4.6* | *0.4* |
| *Nonresidential equipment and software* | *6.3* | *6.8* | *0.5* |
| *Government* | *1.9* | *2.1* | *0.2* |
| *Exports* | *6.9* | *7.0* | *0.1* |
| *Imports* | *6.5* | *6.5* | *0.0* |

Revisions to the nominal series can be divided into two categories of change: definitional and statistical. The definitional changes include such items as recognition of business and government expenditures for software as investment; reclassification of government employee retirement plans; modification of the treatment of private, noninsured pension plans; reclassification of certain transactions as capital transfers; and redefinition of the value of imputed service of regulated investment companies. Of these definitional changes, the major impact comes from the inclusion of business and government expenditures for software in the investment accounts. In the prior NIPA data, business purchases of software were considered as intermediate purchases and not as a final product counted in GDP. The revision places such expenditures in a separate investment category, similar to the manner in which computer hardware is considered as an explicit investment category of final demand.

The statistical changes in NIPA focus primarily on new and revised source data and improved estimating methodologies. The statistical changes include the incorporation of new data from BEA, the Census Bureau, the Bureau of Labor Statistics, the U.S. Department of Agriculture, and the Internal Revenue Service. For example, the new BEA data benchmark 1992 input-output accounts, plus the 1996 annual update of those accounts, provide a better view of sectoral output activity in the economy. In addition, methodological improvements were made in the estimation of the real value of unpriced banking services.

*Table 5. Revisions to nominal GDP, 1959-1998*

| Revision | 1959 | 1982 | 1987 | 1992 | 1996 | 1997 | 1998 |
|---|---|---|---|---|---|---|---|
| **Change in nominal GDP (billion dollars)** | **0.2*** | **17.1** | **50.2** | **74.5** | **151.6** | **189.9** | **248.9** |
| Definitional | -0.1 | 19.9 | 44.1 | 78.3 | 123.7 | 140.9 | 169.0 |
| Statistical | 0.3 | -2.8 | 6.0 | -3.8 | 27.9 | 49.0 | 80.0 |
| **Change relative to previous NIPA-defined nominal GDP (percent)** | **0.0** | **0.5** | **1.1** | **1.2** | **2.0** | **2.3** | **2.9** |
| Definitional | 0.0 | 0.6 | 1.0 | 1.3 | 1.6 | 1.7 | 2.0 |
| Statistical | 0.0 | -0.1 | 0.1 | -0.1 | 0.4 | 0.6 | 0.9 |

*Total does not equal sum of components due to independent rounding.

Table 5 shows the revisions to the nominal dollar valuation of GDP for various years, breaking down the changes into definitional and statistical components. While the definitional changes tend to be larger, primarily because of the changes made to reflect software purchases, the statistical changes from 1996 and beyond are a growing portion of the overall change.

Table 6 presents a more detailed breakout of the data for 1998, indicating which components of GDP are affected the most and how they change the aggregate value for nominal GDP. The table shows the value of the difference between the old and new valuations, broken out by component of GDP. The table highlights the role of software changes in the revised accounts. For 1998, the incorporation of software as a final demand category—nonresidential equipment and software plus the investment in software for the Government—accounts for 63 percent of the total nominal revision of $248.9 billion.

## Implications for Economic Growth and Energy Demand

The revision to the economic data underlying NIPA has implications both for the forecasting of economic growth and for the derivation of energy demand to support the projected growth. From both perspectives, the central question is how to interpret the new data. As highlighted in Tables 5 and 6, much of the revision is definitional in nature, particularly with the new accounting for software purchases. Does this signify a new view of the economy, recognizing that the old accounts undervalued growth in the aggregate economy; or do the new data simply transform how we look at the economy, with no dramatic reassessment of the growth potential of the underlying economy? An early assessment by Standard & Poor's DRI (DRI) of the role of the accounting changes tended to focus on the redefinitional aspects, with no strong feeling that the revisions signaled a "new economy" [*22*]. Later articles from both DRI and the WEFA Group (WEFA) highlight the recent rapid increase in productivity growth in the economy. A series of articles in *The Economist* provides an excellent summary of the debate about recent productivity trends [*23*]. The changes to the accounts reflect a more complete representation of investment through the software revisions and indicate that the true growth potential of the economy was undervalued historically.

*Table 6. Revisions to nominal GDP for 1998 (dollars)*

| Component | Total | Definitional | Statistical |
|---|---|---|---|
| **GDP** | **248.9*** | **169.0** | **80.0** |
| Consumption | 40.7 | 29.1 | 11.6 |
| Investment | 164.1 | 123.4 | 40.7 |
| Nonresidential equipment and software | 127.2 | 123.4 | 3.8 |
| Government | 42.6 | 16.7 | 25.9 |
| Investment: software | 28.5 | 28.5 | 0.0 |
| Net exports | 1.6 | 0.0 | 1.6 |

*Total does not equal sum of components due to independent rounding.

Table 7 shows growth rates for the last four decades for three key indicators: real GDP, the labor force, and a simple comprehensive measure of productivity showing the value of real GDP generated per member of the labor force. With the pre-revision data, the growth rate of the economy slowed each decade relative to the 1960s. The rapid labor force growth of the 1970s, due to expanded entry of women into the work force, was offset by low productivity growth. During the 1980s and 1990s, productivity

*Table 7. Historical growth in GDP, the labor force, productivity and energy intensity (percent per year)*

| Growth rate | 1960-1970 | 1970-1980 | 1980-1990 | 1990-1998 |
|---|---|---|---|---|
| **Before revision** | | | | |
| Real GDP | 4.1 | 3.1 | 2.9 | 2.6 |
| Labor force | 1.7 | 2.6 | 1.6 | 1.1 |
| Productivity | 2.4 | 0.5 | 1.2 | 1.5 |
| Energy intensity | 0.0 | -1.6 | -2.1 | -1.1 |
| **After revision** | | | | |
| Real GDP | 4.2 | 3.2 | 3.2 | 3.0 |
| Labor force | 1.7 | 2.6 | 1.6 | 1.1 |
| Productivity | 2.4 | 0.6 | 1.5 | 1.9 |
| Energy intensity | 0.0 | -1.7 | -2.4 | -1.5 |

increases partially offset slowing growth in the labor force. With the post-revision data, the view of the economy is altered. The dropoff in real GDP growth is moderated somewhat. The change is attributable to slightly higher measures of productivity growth in the economy.

Three trends are evident: (1) of the four decades, productivity growth was far stronger in the 1960-1970 period than in any subsequent decade (although the second half of the 1990s had comparable productivity growth); (2) the revisions to the NIPA tables substantially increase the perceived growth in output per member of the labor force; and (3) energy intensity per unit of output has declined more rapidly in recent decades than was previously thought. The latter change is directly related to the revised upward growth of the real GDP series.

As the gap between the GDP growth rates before and after revision widens across the decades, the gap between the corresponding productivity growth rates also widens. In the period from 1990 through 1998, the real GDP annual growth rate has been revised upward from 2.6 percent to 3.0 percent, and the annual growth rate in GDP per member of the labor force has moved from 1.5 percent to 1.8 percent. The growth in productivity in the 1990s has been associated by some with the development of a "new economy" associated with continually improving communication and real time information. Future releases of data, based on the new accounting conventions, will shed light on the prospects for sustained rates of GDP growth in the face of slowing population and labor force growth rates.

A measure of the energy intensity of the economy can be computed as the ratio of energy consumption to real GDP. Table 7 shows growth rates for the decline in energy intensity by decade, and Figure 8 shows energy intensity before and after revision, indexed to 1.0 in 1960. During the 1960s, energy consumption grew at roughly the same rate as real GDP. Although energy intensity declined slightly in mid-decade, by 1970 the index returned to approximately the 1960 level. With energy prices rising during the 1970s and early 1980s, however, energy intensities declined rapidly as consumers and producers adjusted their energy use in response to higher prices. In the late 1980s and during the 1990s, the growth in the economy was accompanied by generally declining energy prices, and the rate of energy intensity decline slowed.

The revisions to the NIPA data, by reflecting a higher rate of real GDP growth, lead to a revised view of the rate of decline in the energy intensity of the economy. For each decade since the 1960s, the measure of energy intensity declines at a faster rate than previously thought.

Figure 9 summarizes the effects of the NIPA revisions on both historical growth in the economy and for projections through 2020. The figure shows a moving 21-year average annual growth rate for real GDP, with the value for each year calculated as the average annual growth rate over the preceding 21 years [*24*]. For history, GDP growth between 1959 and 1980 (21 years) averaged 3.6 percent per year. The pre-revision data indicated that, in the period between 1978 and 1999, the real GDP growth rate was 2.7 percent per year; however, with the new revisions to the NIPA data, the growth rate between 1978 and 1999 is now calculated at 3.0 percent, an upward revision of 0.3 percentage points.

***Figure 8. Index of energy use per dollar of gross domestic product, 1960-1998 (index, 1960 = 1.0)***

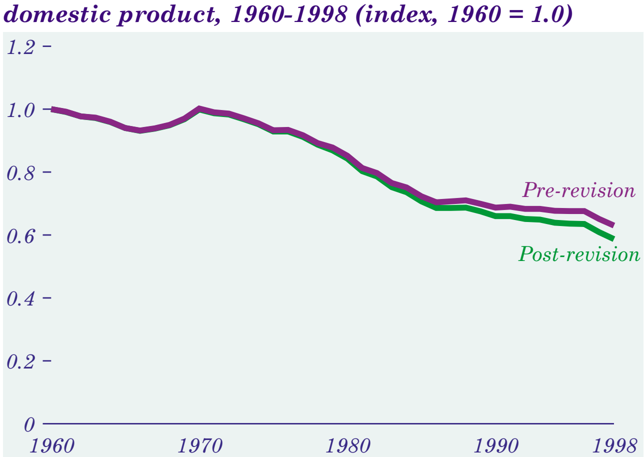
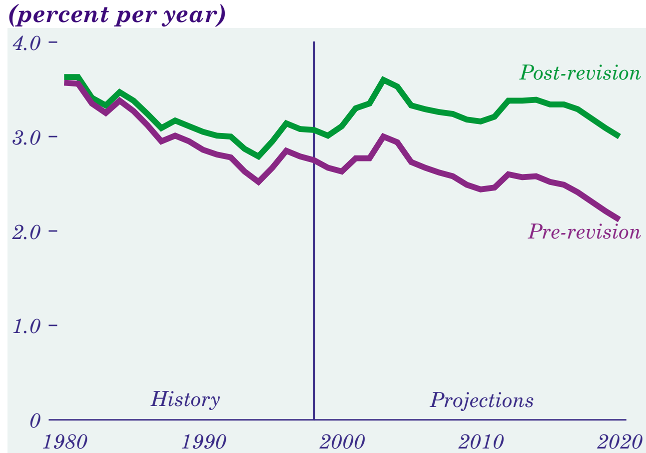



***Figure 9. Annual growth in real gross domestic product: 21-year moving average, 1980-2020 (percent per year)***



The revisions to the NIPA data do not represent a one-time shift in historical growth rates but, instead, show a growing differential over time. The differential is expected to continue growing over the forecast period. The forecast portion of the pre-revision line in Figure 9 shows the GDP growth rates projected in the *Annual Energy Outlook 2000* (*AEO2000*). The forecast portion of the post-revision line shows the GDP growth rates projected in *AEO2001*. The 21-year average annual growth rate between 1999 and 2020 has been revised upward from 2.1 percent in *AEO2000* to 3.0 percent in *AEO2001*, for a revision difference of 0.9 percentage points.

What implications will the revisions have for the U.S. energy system and, specifically, for the derivation of energy demand in the forecast? Table 8 presents a forecast comparison of key macroeconomic variables for the energy system. The table compares the projected growth rates of the key variables from 1999 through 2020 in the *AEO2000* and *AEO2001* forecasts. The table also shows historical data for the periods 1980-1990 and 1990-1999. The projected growth rates for population and the labor force are essentially the same, but the projected annual growth rate for real GDP, which was 2.1 percent in the *AEO2000* forecast, is 3.0 percent in *AEO2001*, reflecting the underlying changes in the NIPA data.

The projected annual growth in disposable income has also been revised upward, from 2.4 percent in *AEO2000* to 3.0 percent in *AEO2001*; and the expected growth in commercial floorspace has increased from 1.0 percent to 1.3 percent per year. Industrial output (agriculture, mining, construction, and manufacturing) has also been revised upward, from 1.9 percent to 2.6 percent growth annually, and the growth rate for manufacturing output has been revised from 2.0 percent to 2.8 percent. Within manufacturing, the change in growth is predominantly within the non-energy-intensive sectors of the economy, with only a small upward revision in the energy-intensive sectors. Figure 10 shows the projected sectoral composition of growth for *AEO2001*.

How does the revised view of historical economic growth and energy intensity decline translate into changes to the forecasts for the four basic energy demand sectors of the economy? In the residential sector, increased growth in disposable income will influence consumer demand for energy, particularly for miscellaneous electrical appliances such as home theater systems and personal computers. The projected increase in disposable income and the slight increase in population in *AEO2001* lead to an increase in the number of housing starts expected over the forecast period relative to *AEO2000*. The increase in the projection for population growth stimulates the rise in housing starts, and the increase in the projection for disposable income influences the type and size of house built. Single-family homes

***Figure 10. Projected average annual growth in sectoral output, 1999-2020 (percent per year)***

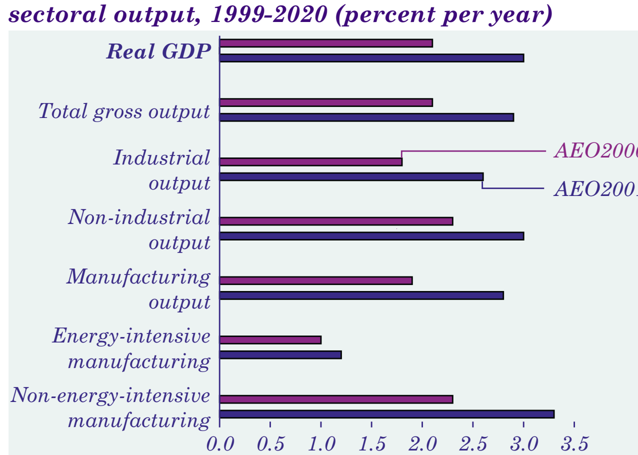



***Table 8. Forecast comparison of key macroeconomic variables***

| | History | | Projections, 1999-2020 | |
|---|---|---|---|---|
| | *1980-1990* | *1990-1999* | *AEO2000* | *AEO2001* |
| | Growth rate (percent per year) | | | |
| ***Real GDP*** | ***3.2*** | ***3.2*** | ***2.1*** | ***3.0*** |
| *Population age 16 and over* | *1.1* | *1.0* | *0.9* | *0.9* |
| *Labor force* | *1.6* | *1.1* | *0.9* | *0.9* |
| *Disposable income* | *3.0* | *2.9* | *2.4* | *3.0* |
| *Commercial floorspace* | *2.0* | *1.5* | *1.0* | *1.3* |
| *Industrial output* | *1.6* | *2.6* | *1.9* | *2.6* |
| *Manufacturing output* | *1.6* | *2.8* | *2.0* | *2.8* |
| *Energy-intensive sector output* | *0.9* | *1.6* | *1.0* | *1.2* |
| *Non-energy-intensive sector output* | *1.9* | *3.3* | *2.3* | *3.3* |
| | Period average (million per year) | | | |
| *Total housing starts* | *1.75* | *1.67* | *1.86* | *2.01* |
| *Unit sales of light-duty vehicles* | *13.49* | *14.54* | *16.02* | *16.70* |

tend to be larger and more energy-intensive than either multifamily or mobile homes, increasing the need for energy to heat, cool, and light the larger living spaces. On average, the projected use of delivered energy per household by 2020 is roughly 6 percent higher in *AEO2001* than it was in *AEO2000*; however, energy use per square foot is expected to decline slightly over the forecast horizon, with gains in energy efficiency projected to offset growth in consumer electronics.

Commercial floorspace is also projected to expand more rapidly in the *AEO2001* forecast, but with little change in the projections for population growth and labor force growth, the change in projected growth in total floorspace is not as great as the change in projected real GDP growth. In *AEO2001*, commercial floorspace is projected to grow by 1.3 percent per year over the forecast period, up from 1.0 percent per year in the *AEO2000* forecast. Figure 11 illustrates the *AEO2001* projections for commercial energy intensity by major fuel. Intensity is defined in terms of delivered energy use per square foot of floorspace, reflecting the direct influence of floorspace on commercial energy demand for major services such as space conditioning and lighting. The continuing trend toward greater use of computers and new types of electronic equipment in conducting business transactions and providing services is reflected in the projected increase in the intensity of electricity use in commercial buildings.

Industrial output in the economy is projected to grow more rapidly in *AEO2001* than was projected in *AEO2000*; however, the definitional portion of the NIPA revisions is not the primary reason. Whether an industry's output is defined as an intermediate good (not included in GDP) or a final demand good (included in GDP) does not by itself affect the inputs required to produce the output, but increased GDP growth resulting from higher productivity does lead to increased growth in industrial output. All sectors of the economy are projected to grow faster, but the most rapid growth is projected to occur outside the energy-intensive sectors. The energy-intensive industries' share of industrial output is projected to fall more rapidly in *AEO2001* (1.3 percent per year) than in *AEO2000* (0.9 percent per year) as a result of expected higher growth in computer-related manufacturing industries. Delivered energy intensity, measured as thousand Btu per dollar of output, is projected to fall by 1.4 percent per year in *AEO2001*, as compared with 0.8 percent per year in *AEO2000*, over the 1999-2020 period. The *AEO2001* projected trends in industrial energy intensity by major fuel are all downward sloping over the next two decades, as shown in Figure 12.

In the transportation sector, the higher expected growth rates for disposable income and GDP in *AEO2001* lead to higher travel forecasts than in *AEO2000*. Light-duty vehicle travel is projected to increase at an annual rate of 1.9 percent from 1999 through 2020, as opposed to the 1.7 percent projected in *AEO2000*. Air travel, including personal, business, and international flights, is projected to expand at 3.6 percent per year, almost twice the rate of increase in light-duty vehicle travel. In *AEO2001*, freight truck travel which is very dependent on industrial output growth, is projected to grow more rapidly than projected in *AEO2000*. Although vehicle sales for all travel modes are projected to increase in the forecast as a result of higher travel levels, improvements in stock efficiency proceed more

***Figure 11. Projected commercial delivered energy intensity by fuel, 1999-2020 (thousand Btu per square foot)***

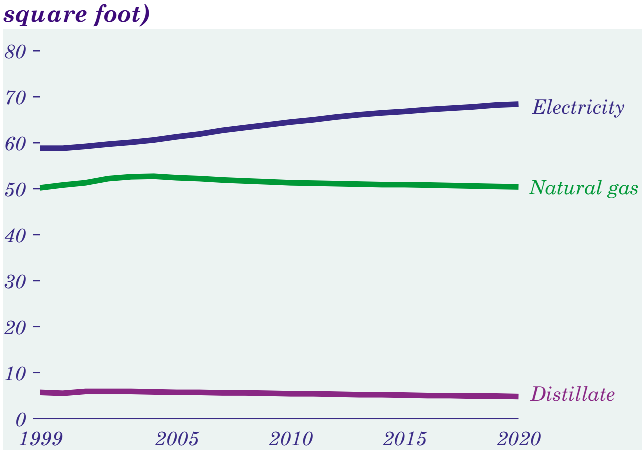
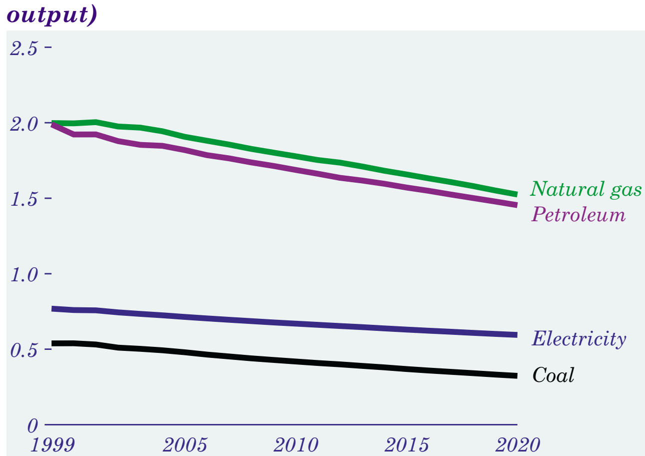



***Figure 12. Projected industrial energy intensity by fuel, 1999-2020 (thousand Btu per 1992 dollar of output)***



slowly for most modes of transportation. Slow turnover of the vehicle stocks and the magnitude of the stocks relative to the volume of new vehicle sales limit the expected improvements in stock efficiency (Figure 13).

The change in energy demand forecasts as a result of the NIPA revisions does not correspond exactly to the change in the forecast for real GDP growth. The NIPA statistical changes reflect different approaches to measuring growth in economic activity as well as a direct upward revision of the actual growth rate of the economy. Definitional changes, which reflect a movement of previously measured activity from one account to another, do not automatically increase energy consumption; however, if the definitional changes help to explain underlying productivity changes in the economy, then they may serve to revise the prospects for growth in economic activity and energy demand. *AEO2001* presents a forecast of future economic growth that takes into account the revised BEA view of historical growth in the economy.

## World Oil Demand and Prices

*AEO2000* was released in November 1999, during a period in which world oil prices were beginning to rise from some of the lowest levels of the past 50 years. The major contributors to the low price environment had been reduced growth in oil demand by the developing economies of the Pacific Rim and increased production by the Organization of Petroleum Exporting Countries (OPEC) that resulted in an oil supply surplus. *AEO2000* anticipated that the rebounding oil prices would stabilize at about $21 per barrel (1998 dollars); however, the upward movement of oil prices has been persistently robust. In August 2000 the refiner acquisition cost of imported crude oils was almost $29 per barrel in nominal dollars. Figure 14 illustrates the oil-price turbulence that has defined the world oil market over the past 3 years.

Three factors have contributed to the continuing surge in world oil prices. First, OPEC members exhibited uncharacteristic discipline in adhering to their announced oil production cutback strategies in 1998 and 1999. Joined by several non-OPEC producers (Mexico, Norway, Oman, and Russia), OPEC cut oil production in order to boost prices and increase revenues. Second, the increase in non-OPEC production brought about by higher oil prices has been only modest. In the aftermath of the low price environment of 1998 and early 1999, oil companies have been slow to commit capital to major oil field development efforts, especially for riskier offshore, deepwater projects. Profitability standards appear to have been somewhat tightened, resulting in a greater lag time between higher prices and increases in drilling activity and an even slower reaction time between drilling and production. Third, the renewed growth in oil demand in the recovering economies of the Pacific Rim has been stronger than anticipated.

The turbulence of world oil prices has a significant impact on short-term markets. The oil market perspective presented in *AEO2001*, however, is a business-as-usual perspective that does not incorporate oil price volatility brought about by unforeseen political or social circumstances. Historically, only disruptions in oil supply brought about by politically motivated actions (such as the oil embargo of 1974) or conflicts involving major oil producers (such as the Iranian Revolution and the Iran-Iraq War) have had

***Figure 13. Projected new light-duty vehicle and on-road stock fuel efficiency, 1999-2020 (miles per gallon)***

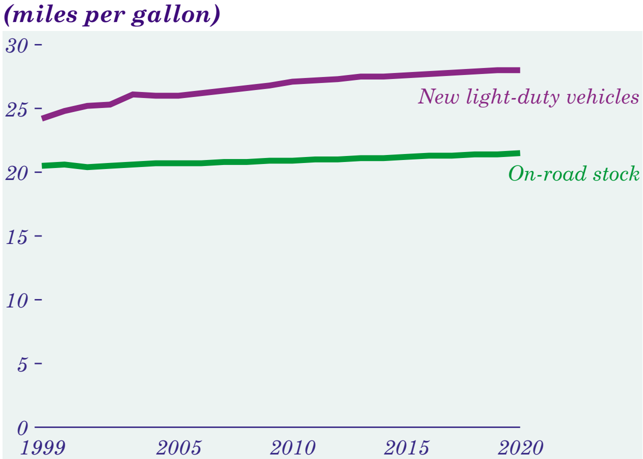
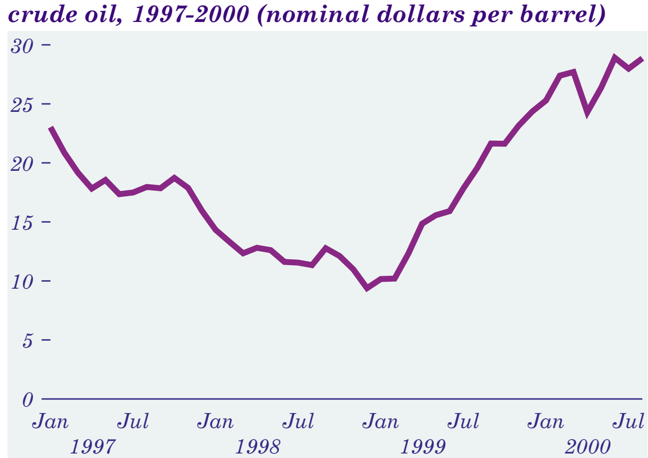



***Figure 14. Refiner acquisition cost of imported crude oil, 1997-2000 (nominal dollars per barrel)***



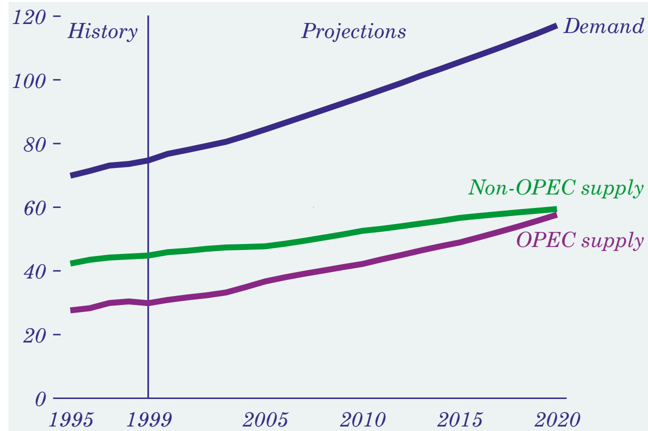
lingering, long-term impacts on oil prices. The oil market volatility over the past several years has been the result of oil market fundamentals that are reasonably well understood but nearly impossible to predict. Traditionally, such near-term oil market gyrations are considered unlikely to have significant impact on long-term markets. Because of this assumption, the *AEO2001* price path converges with last year's path by 2003.

Current high prices are expected to fall for three reasons. First, sustained high oil prices have the potential to damage the economic strength of industrialized and developing nations and delay the full economic recovery of the Pacific Rim nations. OPEC has attempted to avoid those outcomes by easing production restraints during 2000 in order to soften prices somewhat. Second, continued high prices cannot help but have a downward impact on worldwide oil demand due to higher prices and the resulting higher inflation, rising interest rates, and eroding consumer confidence. Third, although non-OPEC producers have been somewhat slow in reacting to higher oil prices, there remains significant untapped production potential worldwide, especially in deepwater areas of the Caspian Basin and the Atlantic Basin off West Africa and Latin America.

Although the long-term price paths in *AEO2000* and *AEO2001* are similar, the *AEO2001* projections of world oil demand are higher—by about 5 million barrels per day in 2020—than those in *AEO2000*. Demand expectations for China, the developing countries of the Pacific Rim, and the Middle East have been revised upward, based on a more optimistic long-term assessment of economic growth in those regions. Even with the increases in the demand forecast, however, the long-term expectations for world oil prices remain virtually unchanged as a result of an equivalent increase in worldwide oil production potential that is based on a recent assessment (June 2000) of ultimately recoverable oil resources prepared by the U.S. Geological Survey (USGS) [*25*].

The June 2000 USGS assessment of world oil production potential identifies about 700 billion barrels of ultimately recoverable oil over and above the previous (1994) USGS assessment. About one-third of the newly identified oil is located in the Caspian Basin region, and the Atlantic Basin (deepwater offshore production potential in West Africa and Latin America) accounts for almost another third. Middle East natural gas liquids and additional volumes from enhanced oil recovery technologies make up

***Figure 15. World oil supply and demand forecast in the AEO2001 reference case, 1995-2020 (million barrels per day)***




most of the remainder of the incremental oil. Figure 15 illustrates the long-term outlook for oil demand, OPEC supply, and non-OPEC supply in *AEO2001*.

## Natural Gas Supply Availability

The record high for U.S. annual consumption of natural gas—22.1 trillion cubic feet—was set in 1972. It was followed by a decline to a low of 16.2 trillion cubic feet in 1986, from which the market has been recovering ever since. Preliminary estimates indicate that the 1972 record may be broken in 2000. The 1972-1986 decline in natural gas consumption was brought on in part by a cumbersome regulatory structure that did not allow the market to respond to price signals in a timely and efficient manner. Producers were constrained by price controls that discouraged production, and consumers were constrained by moratoria placed on the construction of new gas-burning units.

Curtailments of natural gas supplies during the bitterly cold winter of 1976-1977 fueled a perception among consumers that natural gas was a scarce and unreliable resource. In response to the curtailments, Congress in 1978 passed the Natural Gas Policy Act (NGPA), the objective of which was to provide a phased decontrol of natural gas wellhead prices. NGPA signaled the beginning of an era of industry restructuring that is still proceeding. In addition to wellhead price decontrol, which was completed with the passage of the Wellhead Decontrol Act of 1989, restructuring of the interstate pipeline industry was undertaken.

The first phase of restructuring began in 1985 with Federal Energy Regulatory Commission (FERC) Order 436, requiring pipelines to provide open access to transportation services. It was followed by FERC Order 636 in 1992, which allowed for a major restructuring of interstate pipeline operations. The most notable provisions of Order 636 were the separation of sales from transportation services, rate redesign, and capacity release authority. In February 2000, FERC's most recent ruling, Order 637, further refined the remaining pipeline regulations in an effort to address inefficiencies in the capacity release market. FERC has indicated that it will continue a dialog with both industry and consumers in order to promulgate future changes that will foster market efficiency.

The restructuring of the natural gas industry has been effective, leading to open competition in the industry and to a much healthier market that is driven by supply and demand forces rather than by regulation. The market has grown steadily since 1986, with both production and pipeline deliverability showing significant increases. Natural gas is now perceived as an abundant, reliable resource that is expected to fuel an increasing share of domestic energy consumption well into the future.

Natural gas consumption, which accounted for 23 percent of domestic energy use in 1999, is expected to grow more rapidly than any other major fuel source from 1999 to 2020, mainly because of projected growth in gas-fired electricity generation. Consumption is projected to reach 30 trillion cubic feet in 2013 and continue rising to almost 35 trillion cubic feet in 2020. Gas consumption by electricity generators (excluding cogenerators) in 2020 is expected to be triple the 1999 level. As demand increases, pressure on natural gas supply will grow.

Technically recoverable natural gas resources in North America are believed to be adequate to sustain the production volumes projected in *AEO2001*. The current high prices are expected to come down once the effects of increased drilling are realized, and advances in technology over the long term are expected to make it possible to produce more of the technologically recoverable resources economically. Domestic consumption still is expected to increase at a faster rate than domestic production over the forecast period, with imports making up the difference. Natural gas imports have been rising significantly in recent years, and in percentage terms they are expected to outpace domestic production over the forecast. In addition, generally rising wellhead prices, relatively abundant natural gas resources, and technology improvements, particularly for producing offshore and unconventional gas, are expected to contribute to production increases that will keep pace with the remainder of the projected increase in demand.

### *Short-Term Situation*

Natural gas prices have increased sharply in 2000, especially in the spot market, where prices since the summer have generally exceeded $5.00 per thousand cubic feet. The average wellhead price for 2000 is expected to be relatively high, at about $3.37 per thousand cubic feet. This is because of a tight natural gas supply situation resulting from low gas storage levels, an increase in natural gas use for electricity generation as new gas-fired power plants have come on line, and a decline in natural gas drilling that has resulted from generally low prices over the past few years. Low storage levels have resulted from injection rates that have run about 10 percent below historically average rates throughout the refill season. Underground working gas storage levels in September 2000 were about 12 percent below September 1999 levels and about 10 percent below the average for the past 5 years [*26*]. In nominal terms, the expected 2000 wellhead price would be the highest annual wellhead price on record, although it would be lower in inflation-adjusted terms than the prices faced in the early 1980s. Average natural gas wellhead prices this coming winter are projected to be nearly double those seen last year.

Recent higher prices have caused U.S. exploration and drilling to rebound, but the 6- to 18-month lag between drilling increases and market availability of additional product makes it unlikely that a significant amount of additional natural gas supply will be available before mid-2001. Prices in 1998 were low enough to cause cash flow problems in the industry that will delay the response to higher prices longer than usual. Production companies had to replenish investment funds and, in many cases, pay off debt before investing in new projects [*27*].

Slight production increases from increased drilling are already being seen, however, and the Energy Information Administration (EIA) anticipates that further increases will eventually lead to lower prices. Nevertheless, prices over the next year are likely to remain above $3.00 per thousand cubic feet. The current situation is the result of short-term supply imbalances that are expected to even out over the longer term, moving the market toward equilibrium. Natural gas supplies to meet the forecast demand are available from numerous sources, including imports.

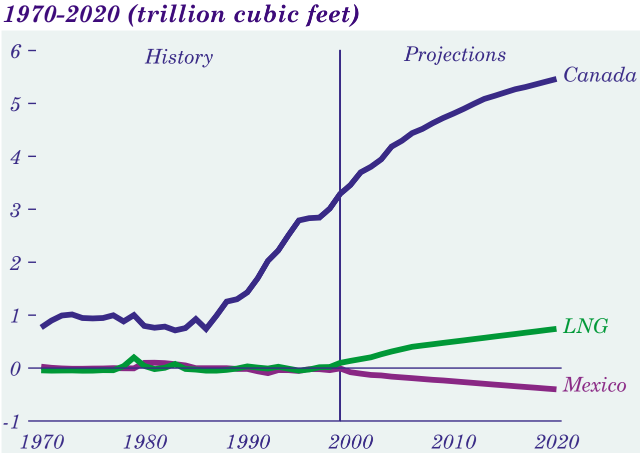
### *Imports*

In the *AEO2001* forecast, net imports of natural gas are expected to make up the difference between domestic production and consumption (Figure 16). In general, imports are expected to be priced competitively with domestic sources. Imports from Canada, primarily from western Canada and from the Scotian Shelf in the offshore Atlantic, are expected to make up most of the increase in U.S. imports.

Canadian resources of natural gas are substantial. According to a December 1999 study published by the National Petroleum Council, *Meeting the Challenges of the Nation's Growing Natural Gas Demand*, Canada has 64 trillion cubic feet of proved reserves and 603 trillion cubic feet of assessed additional reserves. With most Canadian oil- and gas-producing regions less mature than those in the United States, the potential for additional low-cost production is strong, and imports from Canada are projected to remain competitive with U.S. domestic supplies in the forecast. It is anticipated that current U.S. price levels will entice Canadian suppliers to fill new export capacity on the Alliance pipeline and help alleviate the current tight supply situation.

Although Mexico has a considerable natural gas resource base, gas trade with Mexico has until recently consisted primarily of exports. Although cross-border capacity has recently increased, and Mexican sources predict a continuing growth in exports to the United States, EIA expects Mexico to remain a net importer of natural gas, with imports from Mexico growing by 3.9 percent per year over the forecast period and exports to Mexico growing by 10.8 percent per year. Given the existing cross-border capacity and the size of the resource base, however, Mexico does hold promise for the future as a source of natural gas supply for the United States.

**Figure 16. Net U.S. imports of natural gas, 1970-2020 (trillion cubic feet)**




Liquefied natural gas (LNG) is not expected to become a major source of U.S. supply between 1999 and 2020, but it is projected to provide a growing percentage of natural gas imports. Imports of LNG, at first primarily from Algeria, peaked at 253 billion cubic feet in 1979 and then dropped to 18 billion cubic feet in 1995. The decline resulted both from low natural gas prices that made LNG uneconomical and from the more recent refurbishment of Algerian liquefaction facilities that temporarily reduced supply availability. With the completion of the refurbishment and the advent of new sources of supply (such as Australia, Trinidad and Tobago, and Qatar), imports have been growing and are projected to continue to grow through 2020.

In the past, LNG imports were purchased under long-term contracts with suppliers. More recently, the development of a spot market has made the LNG market more flexible and more able to respond to the short-term needs of both buyers and sellers. Once used primarily to satisfy peaking needs, LNG use for baseload requirements is on the rise. In 1999, U.S. buyers purchased 27 cargos of LNG under spot sales, 19 more than in 1998 [*28*]; and the trend is expected to continue. There is an aggregate existing sustainable capacity of 840 billion cubic feet per year at four U.S. LNG import facilities, all of which are expected to be operational by 2003. Two of the four U.S. facilities—at Cove Point, Maryland, and Elba Island, Georgia—have been mothballed for many years, but plans to reopen both have been announced. As a result, it is anticipated that substantial unused capacity (and expansion potential) will allow LNG imports to grow significantly in the future. In the *AEO2001* reference case, the four U.S. LNG import facilities are projected to be operating at their maximum sustainable capacity by 2020.

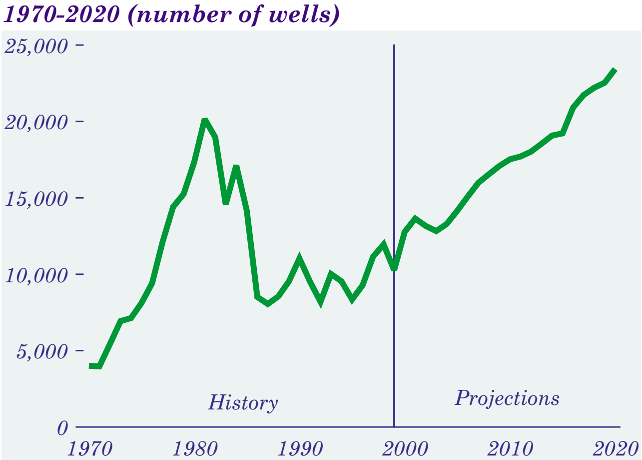
### *Domestic Production*

One of the key activities in producing natural gas is drilling. Price increases are a powerful incentive for increased drilling and the purchase of new drilling equipment. For example, the number of available oil and gas drilling rigs increased by almost 16 percent annually between 1974 and 1982—from 1,767 to 5,644—as natural gas prices more than quadrupled in real terms and oil prices more than doubled [*29*]. In April 1999, after 9 consecutive months of natural gas wellhead prices below $2.00 per thousand cubic feet, the U.S. natural gas rig count for the month was down to 371. Since May 1999, however, wellhead prices have climbed steadily, reaching about $4.25 per thousand cubic feet in September, with preliminary estimates for October of about $4.65 per thousand cubic feet. By November 10, the U.S. natural gas rig count had climbed to 840.

High capital requirements and uncertainty about the actual demand for new rigs have so far limited investment in rig construction. Cost estimates ranging from $115 million for a 350-foot jackup rig up to $325 million for a deepwater semisubmersible rig have been reported [*30*]. Exploration and production budgets for many natural gas producers are expected to increase sharply in the latter part of 2000 and into 2001, however, spurred by higher prices and greatly improved current and expected revenues from producing assets. In the *AEO2001* forecast, the number of natural gas wells drilled is projected to increase from 10,200 in 1999 to 23,400 in 2020 (Figure 17). In view of the historical and current responses to rising prices, it is assumed that the rigs needed to meet such drilling levels will be constructed. It is also assumed that, in the long term, improvements in technology will make individual rigs more productive and temper the need for additional rigs.

The U.S. natural gas industry does face a challenge in terms of expanding its work force. According to the U.S. Bureau of Labor Statistics, employment in the U.S. oil and gas extraction sector peaked in 1982 and, subsequently, lost almost 390,000 jobs from 1982 to 1995. It is true that productivity improvements are reducing the number of employees needed, but the industry must recognize its potential manpower needs and take steps to maintain an appropriate level of oil and gas expertise so as not to be caught short when the expertise is needed. It takes considerable time and effort to attract and train qualified personnel, especially in a cyclic industry where a history of layoffs has discouraged entry into the workforce. The number of jobs needed to support the projected level of production in 2020 is estimated at 411,500 or roughly a 40-percent increase over 1999 employment levels.

***Figure 17. Lower 48 natural gas wells drilled, 1970-2020 (number of wells)***




Most of the projected increase in U.S. natural gas production is expected to come from lower 48 onshore nonassociated sources, with unconventional sources —primarily tight sands and coalbed methane in the Rocky Mountain region—also making a significant contribution. Offshore production, mainly from wells in the Gulf of Mexico, is also expected to contribute to the increase.

Natural gas production is obtained from "proved reserves." Proved or "measured" reserves are the estimated quantities of natural gas that "geological and engineering data demonstrate with reasonable certainty" to be recoverable from known reservoirs under existing economic and operating conditions. At the end of 1999, U.S. proved reserves totaled 167 trillion cubic feet. While proved reserves are diminished each year by the amount of natural gas actually produced, they are also replenished by additions to existing fields through extensions, revisions, and the discovery of new pools or reservoirs within existing fields. Proved reserves are also added through the discovery of new fields.

"Technically recoverable resources" are a broader category of resources that includes proved reserves and consists of estimated quantities of gas that are technically recoverable without reference to economic profitability (Figure 18). As technology advances, identified resources that were once not economically recoverable become economically recoverable. Current estimates of technically recoverable natural gas resources indicate that the resource base is adequate to sustain growing production volumes for many years.

Natural gas resource estimates are derived from assessments by the U.S. Geological Survey for onshore regions and by the Minerals Management Service for offshore areas [*31*]. As of January 1, 1999, U.S. technically recoverable resources were estimated at 1,281 trillion cubic feet, including 164 trillion cubic feet of proved reserves, 244 trillion cubic feet of inferred reserves from known fields, 319 trillion cubic feet of undiscovered conventional resources not associated with oil deposits, and 393 trillion cubic feet of undeveloped resources of unconventional gas from coalbeds and low-permeability sandstone and shale formations. Gas associated with

*Figure 18. Technically recoverable U.S. natural gas resources as of January 1, 1999 (trillion cubic feet)*

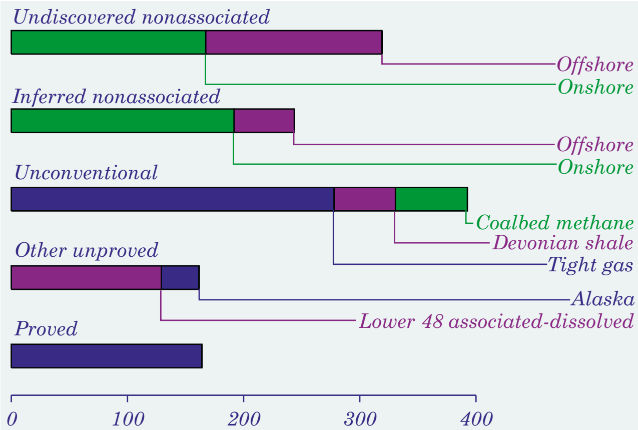
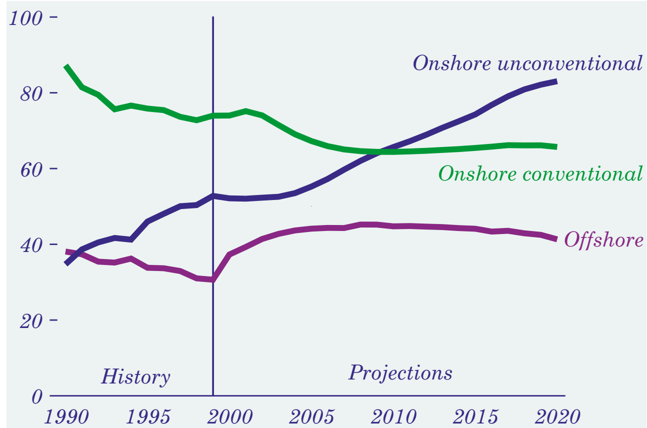



*Figure 19. Lower 48 end-of-year natural gas reserves, 1990-2020 (trillion cubic feet)*




oil makes up most of the balance of the total technically recoverable resource base.

From the early 1980s until the mid-1990s, yearly production of natural gas in the United States exceeded reserve additions, and U.S. natural gas proved reserves were declining. The downward trend was reversed in 1994, and reserves have increased in 5 of the past 6 years. Reserves are expected to increase through most of the forecast period, with increasing onshore unconventional reserves compensating for declines in onshore conventional reserves (Figure 19). As a result, reserves are anticipated to be adequate to sustain the projected levels of production throughout most of the *AEO2001* forecast period, with the average lower 48 production-to-reserves ratio projected to increase from 11.6 percent in 1999 to 15.0 percent in 2020. Lower 48 end-of-year reserves in 2020 are projected to be 21 percent above current levels. The relatively high levels of annual reserve additions reflect increased exploratory and developmental drilling as a result of higher prices and expected strong growth in demand, as well as productivity gains from technological improvements.

### *Natural Gas Resource and Technology Cases*

Uncertainty with regard to estimates of the Nation's natural gas resources has always been an issue in projecting production, and it is widely acknowledged that assessing actual resource levels is a difficult task. To evaluate the sensitivity of the *AEO2001* projections to the estimate of the underlying resource base, high and low resource cases were created. As in the other *AEO2001* cases, resources in areas restricted from exploration and development were not included in the resource base for the sensitivity cases. For conventional onshore and offshore resources, the estimates of undiscovered technically recoverable resources and inferred reserves were adjusted by plus and minus 20 percent in the high and low resource cases. The estimates of unproved resources for unconventional gas recovery, which are more uncertain, were adjusted by plus and minus 40 percent. Thus, the assumed levels of technically recoverable resources were 1,583 trillion cubic feet in the high resource case and 979 trillion cubic feet in the low resource case, as compared with 1,281 trillion cubic feet in the reference case. The resource assumptions for the high and low resource cases are intended to represent significant variations without exceeding a reasonable range. They should not be regarded as representing the upper and lower bounds of possible values for technically recoverable U.S. natural gas resources.

The projections in the high and low resource sensitivity cases suggest that, as would be expected, a larger natural resource base would lead to lower wellhead prices and higher production levels, and a smaller resource base would lead to higher wellhead prices and lower production than projected in the reference case. Natural gas production in 2020 is projected to be 1.3 trillion cubic feet higher in the high resource case and 4.4 trillion cubic feet lower in the low resource case than in the reference case (Figure 20). The average natural gas wellhead price in 2020 is projected to be $2.62 per thousand cubic feet in the high resource case (16 percent lower than projected in the reference case) and $4.53 per thousand cubic feet in the low resource case (45 percent higher than in the reference case) (Figure 21). As expected, reduced resource levels have a more dramatic effect on prices and production than do increased resource levels in the forecast period. In the high resource case, although higher overall productivity puts

***Figure 20. Lower 48 natural gas production in three resource cases, 2000-2020 (trillion cubic feet)***

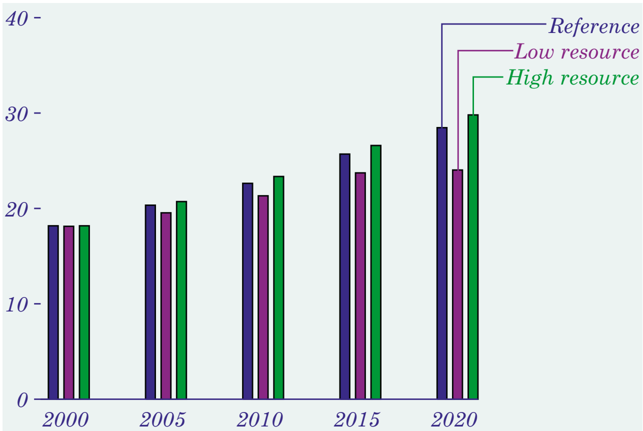
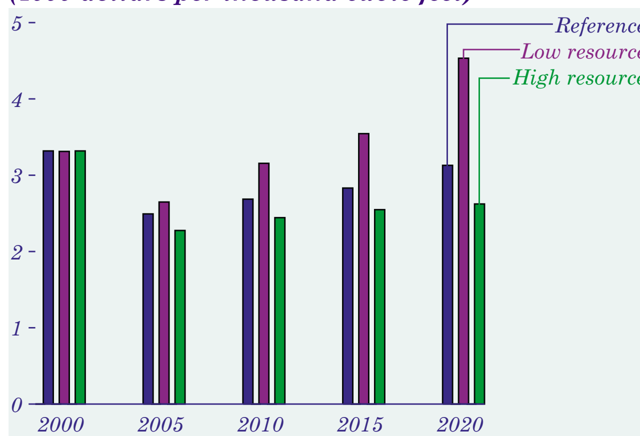



***Figure 21. Average lower 48 natural gas wellhead prices in three resource cases, 2000-2020 (1999 dollars per thousand cubic feet)***




downward pressure on prices, not all the additional resources are available in the projection period because of restraints on growth in rig and drilling activity.

Another area of uncertainty is the future impact of advances in exploration and drilling technologies. In the past, improvements in technology have both reduced exploration and development costs and increased the recoverability of in-place resources. Major advances in data acquisition, data processing, and the technology of displaying and integrating seismic data with other geologic data—combined with lower cost computer power and growing experience with new techniques—have lowered the costs of finding and producing natural gas. Advances in technology over the past 15 years have improved success rates by as much as 50 percent and have allowed higher quality prospects to be targeted, thus improving the overall well productivity.

One significant technological advance, adopted in the latter part of the 1980s, was horizontal drilling. Drilling a horizontal well, as opposed to a conventional vertical well, enables more of the reservoir to be exposed to the wellbore. Another advanced cost-saving technology is fracturing, which involves injecting fluids under high pressure to create new fractures and enlarge existing ones. Fracturing is now widely used to stimulate oil and natural gas production from wells that have declined in productivity. Modern drill bits, such as polycrystalline diamond drill bits, significantly reduce the time required to drill a well and allow drilling in more difficult geologic formations. Other substantial boosts to successful exploration and development have come from the increased use of three- and four-dimensional seismology [*32*] to delineate prospective areas of a formation and the use of remote sensing systems to improve the identification of promising geologic structures. New rig designs, such as jackup rigs, semisubmersible drilling rigs, and modular rigs, and the introduction of subsea well technologies, tension leg platforms, and production spars have opened up vast new and promising areas for exploration in the deepwater areas of the offshore that had been inaccessible.

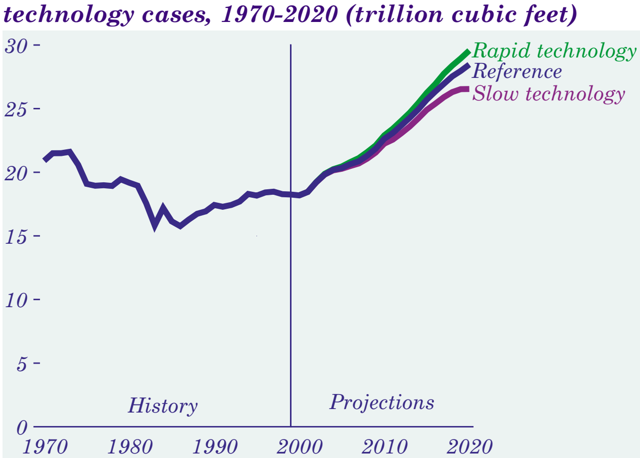
Continued improvements in technology have the potential to provide low-cost, efficient tools that will increase production in a manner that will be profitable to the industry while providing supplies to consumers at reasonable prices. The *AEO2001* reference case assumes that improvements in technology will continue at historical rates. More rapid improvements could yield benefits in the form of both lower prices and increased production. To assess the sensitivity of the *AEO2001* projections to the potential effects of changes in success rates, exploration and development costs, and finding rates as a result of technological progress, rapid and slow technology cases were developed, using the same resource base as in the reference case. The technology improvement rates assumed in the reference case were increased and decreased by 25 percent in the rapid and slow technology cases, which were analyzed as fully integrated model runs. All other parameters in the model were kept at their reference case values, including technology parameters in other energy markets, parameters affecting foreign oil supply, and assumptions about foreign natural gas trade, excluding Canada.

In the rapid technology sensitivity case for natural gas, the assumption of a more rapid pace of technological improvement than assumed in the reference case leads to projections of lower wellhead prices and more production (Figure 22). Slower technology improvements are projected to have the opposite effects in the slow technology case. The projections for total U.S. natural gas production in 2020 are 3.8 percent higher in the rapid technology case and 6.6 percent lower in the slow technology case than in the reference case. The most pronounced effects are on the projections of production from unconventional sources, which are 13.5 percent higher in the rapid technology case and 9.8 percent lower in the slow technology case in 2020 than projected in the reference case.

Although not represented in the rapid and slow technology cases—which assume the same resource base as in the reference case—it is also possible that the rate of future technological advances could affect the amount of natural gas produced from environmentally sensitive areas. At least 551 trillion cubic feet of the remaining untapped natural gas resource base in the United States underlies federally owned lands, almost evenly split between onshore and offshore locations. Approximately 217 trillion cubic feet of gas under Federal lands is estimated to be unavailable for development due to moratoria and/or restrictions and therefore is not included in the resource base assumed in the *AEO2001* reference case.

Offshore drilling is prohibited along the entire East Coast (31 trillion cubic feet, according to the National Petroleum Council), the west coast of Florida (24 trillion cubic feet), and most of the West Coast (21 trillion cubic feet). The National Petroleum Council estimates that 137 trillion cubic feet of gas in the Rocky Mountain area is subject to access restrictions, 29 trillion cubic feet is closed to development, and 108 trillion cubic feet is available with restrictions. As technological improvements make it

***Figure 22. Lower 48 natural gas production in three technology cases, 1970-2020 (trillion cubic feet)***




possible to produce gas while meeting environmental restrictions, some of the resources in those areas may become available. The reference case assumes that approximately 36 trillion cubic feet of gas in the Rocky Mountain area will become available for development by 2015.

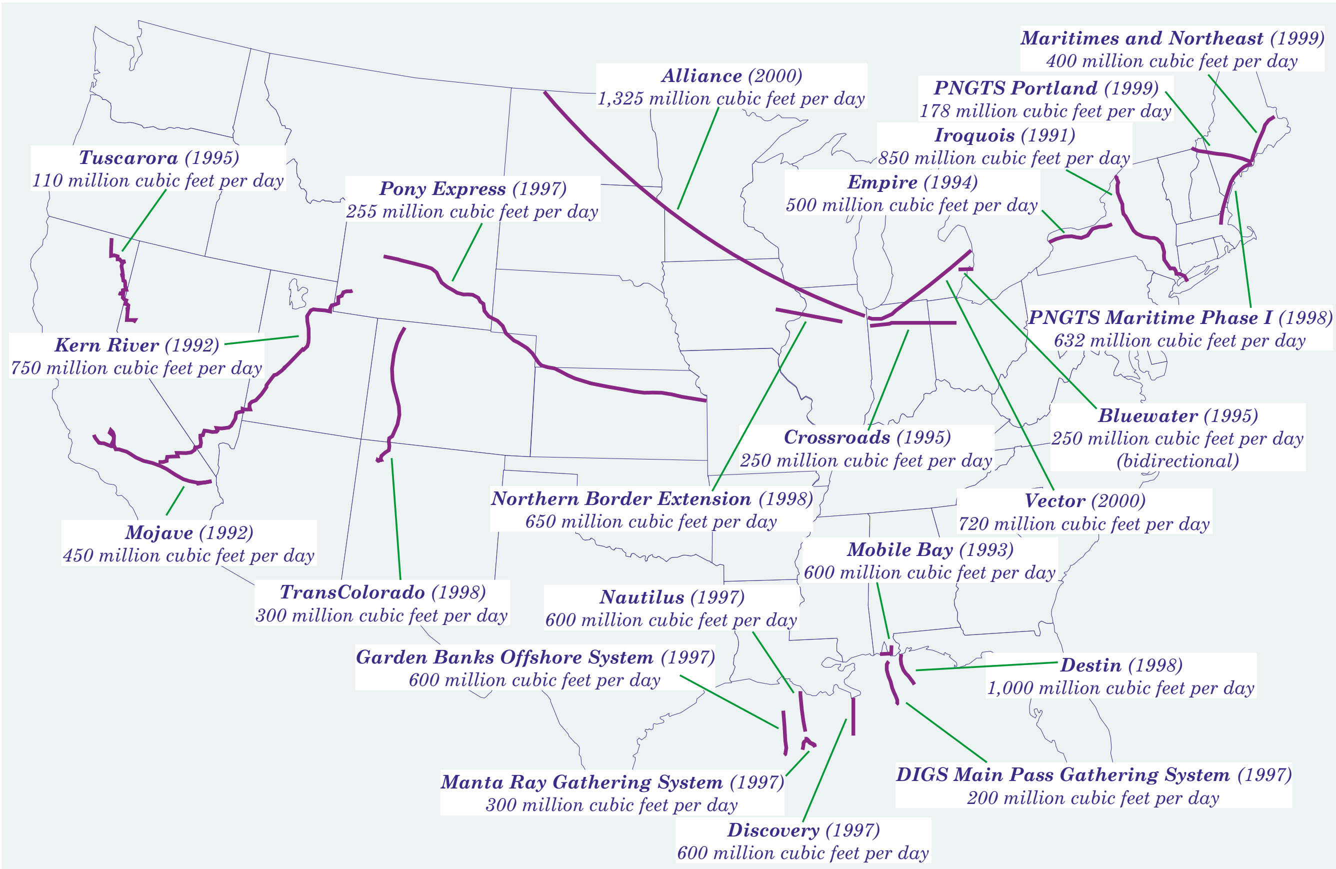
### *Pipeline Capacity Expansion*

The U.S. interstate natural gas pipeline grid grew substantially between 1990 and 2000, with 22 major new interstate pipelines entering service (Figure 23). Additional expansion of the grid would be needed to transport the increased volumes of annual production projected in *AEO2001*. Transportation corridors would have to be expanded to provide access to new and increasing sources of supply. Indeed, much of the expansion projected in the reference case is either already in progress or scheduled to be completed by the end of 2001.

Preliminary estimates indicate that investment in pipeline expansion in 1999 exceeded $2 billion, and that investment in 2000 will reach approximately the same level. Several pipeline projects have already provided producers in the Rocky Mountain region with new access to customers in the Midwest. KN Interstate's Pony Express project and the Trailblazer system expansion have provided access from the Wyoming and Montana production regions, and Transwestern Pipeline and El Paso Natural Gas expansions have increased the capacity to move supplies out of New Mexico's San Juan Basin. Transwestern has increased its capacity by expanding its Gallup, New Mexico, compressor station. The completion in 1998 of a large-scale gathering system in the Powder River Basin significantly increased access to supplies, as did the Frontrunner intrastate expansion. To use the new gathering system, both the Wyoming Interstate and Colorado Interstate pipelines have increased their capacity. Significant increases in flows from the region to markets on the East and West Coasts have already occurred, and additional increases are projected through 2020. In the Gulf Coast offshore region, there has been a considerable increase in gathering systems and short-haul pipelines to move supplies onshore.

The most significant recent additions to pipeline capacity have been made to increase import capacity between the United States and Canada. Capacity has increased by 15 percent since 1998, with the major addition being the Northern Border expansion through Montana into the Midwest. In 1999, U.S. imports from Canada increased by 8.9 percent over the 1998 level, largely due to increased capacity on

*Figure 23. Major new U.S. natural gas pipeline systems, 1990-2000*




the expanded Northern Border Pipeline. Other major expansions are the Alliance Pipeline, also providing access to Western Canada, and the Maritimes and Northeast system to transport Sable Island supplies to markets in New England. The Alliance Pipeline is projected to open in late 2000 with an initial capacity of 1.325 billion cubic feet per day, expanding to 1.83 billion cubic feet per day in the future [*33*]. The Maritimes and Northeast Pipeline became operational on December 31, 1999, with a capacity of about 400 million cubic feet per day at the border. By March 2000, approximately 282 million cubic feet per day was being shipped to New England markets on the Maritimes and Northeast system. Cross-border capacity between the United States and Mexico has also grown, with the major increase resulting from the opening of the Tennessee pipeline near Alamo, Texas. A number of additional projects have been proposed and may proceed if the current trend of increased trade with Mexico continues.

Given the efficiencies that industry restructuring has brought to the U.S. natural gas market, the abundant technically recoverable domestic resource base, the growing availability of natural gas imports, the role of technology in making additional supplies available and reducing costs, and the continuing expansion of the U.S. pipeline grid, the natural gas industry is expected to be able to respond to the challenge of substantial increases in future demand. As long as the industry is confident that the demand will be there and that natural gas can be produced and delivered at prices that are competitive with those of other fuels, the needed investments in drilling, manpower, and pipeline infrastructure are expected to be made.

## Phasing Out MTBE in Gasoline

Methyl tertiary butyl ether (MTBE) is a widely used gasoline blending component. Although it was initially added to gasoline to boost octane, which helps prevent engine knock, the use of MTBE expanded in the 1990s when it was used to meet the 2 percent oxygen requirement in reformulated gasoline (RFG). The Clean Air Act Amendments of 1990 (CAAA90) require RFG to be used year-round in cities with the worst smog problems. In the past few years, the use of MTBE has become a source of debate, because the chemical has made its way from leaking pipelines and storage tanks into water supplies throughout the country. Concerns for water quality have led to a flurry of legislative and regulatory actions at both the State and Federal levels (see “Legislation and Regulations,” page 15).

The Federal proposals are grounded in a set of recommendations made by a “Blue Ribbon Panel” (BRP) of experts convened by the EPA to study the MTBE issue [*34*]. In addition to improving programs to protect against leaking pipelines and storage tanks, the BRP provided a set of recommendations that includes reducing the use of MTBE and amending the Clean Air Act to remove the 2 percent oxygen requirement for RFG while maintaining the current air benefits of reformulated gasoline. The *AEO2001* reference case reflects legislation passed in eight States to restrict the use of MTBE in those States [*35*] but does not assume the implementation of any of the BRP recommendations.

MTBE is an important blending component for RFG because it adds oxygen, extends the volume of the gasoline and boosts octane, all at the same time. In order to meet the 2 percent (by weight) oxygen requirement for Federal RFG, MTBE is blended into RFG at approximately 11 percent by volume, thus extending the volume of the gasoline. When MTBE is added to a gasoline blend stock, it has an important dilution effect, replacing undesirable compounds such as benzene, aromatics, and sulfur. The dilution effect is even more valuable in light of a new ruling by the U.S. Environmental Protection Agency that will require the sulfur content of gasoline to be reduced substantially by 2004 and its recent proposal to maintain benzene at 1998-1999 levels (see “Legislation and Regulations,” page 16). In addition, MTBE is a valuable octane enhancer. Its high octane helps offset the Federal limitations on other high-octane components such as aromatics and benzene [*36*]. If the use of MTBE is reduced or banned, refiners must find other measures to maintain the octane level of gasoline and still meet all Federal requirements.

In the event that the Federal RFG oxygen requirement is waived, replacing the oxygen content in gasoline will not be an issue, but refiners will still need to make up for the loss of volume and octane resulting from banning MTBE. Reliance on other oxygenates, including ethyl tertiary butyl ether (ETBE) and tertiary amyl methyl ether (TAME), is assumed to be limited because of concerns that they have many of the same characteristics as MTBE and may lead to similar problems that affect the water supply. Ethanol, which is now used primarily as an octane booster and volume extender in traditional gasoline, would be the leading candidate to replace MTBE. Ethanol currently receives a Federal excise tax exemption of 54 cents per gallon, which is scheduled to decline to 53 cents in 2001, 52 cents in 2003, and 51 cents in 2005. Legal authority for the Federal tax exemption expires in 2007, but because this exemption has been renewed several times since it was initiated in 1978, the *AEO2001* reference case assumes that the exemption will be extended at the 51-cent (nominal) level through 2020.

Ethanol has some drawbacks that have made it less attractive to refiners than MTBE as an oxygenate. Ethanol results in higher emissions of smog-forming volatile organic compounds (VOCs) than MTBE. Its higher volatility makes it more difficult to meet emissions standards, especially in the summertime when RFG must meet VOC emissions standards. Ethanol’s volatility also limits the use of other gasoline components, such as pentane, which are highly volatile and must be removed from gasoline to balance the addition of ethanol.

In addition to being more volatile than MTBE, ethanol contains more oxygen. As a result, only about half as much ethanol is needed to produce the same oxygen level in gasoline that is provided by MTBE. The result is a volume loss, because the other half of the displaced MTBE volume must come from other petroleum-based gasoline components. The “dilution effect” of ethanol is not as great as that of MTBE, because the use of smaller volumes of ethanol is not as effective in diluting the undesirable qualities of the crude-based blending components [*37*]. Finally, finished fuel-grade ethanol currently contains small amounts of sulfur (between 2 and 8 parts per million), all of which comes from the “denaturant” additive blended with pure ethanol to make it undrinkable [*38*]. The sulfur content of the denaturant could become an issue for gasoline blending as refiners strive to meet a new Federal requirement for low-sulfur gasoline after 2004 (see “Legislation and Regulations,” page 14).

The prospect of increased use of ethanol also poses some logistical problems. Unlike gasoline blended with MTBE and other ethers, gasoline blended with ethanol cannot be shipped in multi-fuel pipelines in the United States. Moisture in pipelines and storage tanks causes ethanol to separate from gasoline. When gasoline is blended with ethanol, the petroleum-based gasoline components are shipped separately to a terminal and then blended with the ethanol when the product is loaded into trucks. Thus, changes in the current fuel distribution infrastructure would be needed to accommodate growth in "terminal blending" of ethanol with gasoline. Alternatively, changes in pipeline and storage procedures would be needed to allow ethanol-blended gasoline to be transported from refineries to distributors.

Ethanol supply is another significant issue, because current ethanol production capacity would not be adequate to replace MTBE nationwide. At present, ethanol supplies come primarily from the Midwest, where most of it is produced from corn feedstocks. Shipments to the West Coast and elsewhere via rail have been estimated to cost an additional 14.6 to 18.7 cents per gallon for transportation [*39*]. If the demand for ethanol increased as a result of a ban on MTBE, ethanol would need to be produced as a fuel on a regular basis; however, higher prices could make new ethanol facilities economically viable, and sufficient capacity could be in place depending on the timing of the MTBE ban.

The *AEO2001* reference case incorporates MTBE bans or reductions in the States where they have passed but does not include any proposed State or Federal actions or the proposed oxygen waiver. Arizona, California, Connecticut, Maine, Minnesota, Nebraska, and New York will ban the use of MTBE within the next several years, and South Dakota will limit the amount of MTBE that can be added to gasoline to 2 percent by volume.

The *AEO2001* projections are developed from a regional model, which captures the effects of limitations on MTBE in individual States through adjustments to assumptions about regional supplies of gasoline. The adjustments are made to reflect shifts in oxygenate selection and gasoline characteristics and changes in average gasoline prices in specific regions. Because the regional price changes are projected only on an annual basis, however, localized price spikes that might occur as a result of State MTBE bans may not be reflected in the model results.

To examine the implications of a possible nationwide ban on MTBE, a sensitivity case was developed using the following assumptions:

- A complete ban on MTBE in gasoline nationwide by 2004
- A waiver of the 2 percent oxygen requirement for Federal RFG
- No renewable standard that would require a specific level of ethanol in RFG
- No loss of air quality benefits from the use of RFG.

Beyond its use as an oxygenate, ethanol is assumed to be used to boost octane and extend volume in gasoline. Given that no renewable standard is assumed, the amount of ethanol use projected in the sensitivity case can be viewed as a floor for ethanol blending.

Despite the assumed removal of the Federal RFG oxygen requirement, the MTBE ban case projects more ethanol blending into gasoline than is projected in the reference case, because additional ethanol would be needed to offset the octane and volume loss that would result from banning MTBE. Ethanol blending in the MTBE ban case is projected to be 194,000 barrels per day in 2004, 55,000 barrels per day higher than projected in the reference case. By comparison, the 1999 level of ethanol use for gasoline blending was about 91,000 barrels per day.

Average U.S. gasoline prices in the MTBE ban case are projected to be 3.5 cents per gallon higher than in the reference case in 2004. (Prices are based on marginal costs.) The higher projected gasoline prices reflect increased costs from blending additional ethanol and other high-octane blendstocks. The MTBE ban case also projects increased imports of petroleum products and reduced imports of crude oil. Net imports of petroleum products are projected to be 150,000 to 200,000 barrels per day higher in the MTBE ban case than in the reference case in the 2004 to 2006 time frame.

A waiver of the Federal oxygen requirement is expected to result in a more cohesive gasoline market in California than assumed in the reference case, because two-thirds of the State currently is bound by Federal requirements and does not use the California Phase III gasoline used elsewhere in the State. As a result, ethanol consumption on the West Coast in 2004 is projected to be 32,000 barrels per day lower in the MTBE ban case than in the reference case.

## Distributed Electricity Generation Resources

Distributed electricity generation resources are included in the *AEO2001* projections for three broadly defined sectors: electricity generators, buildings (residential and commercial), and industrial. In the electricity generation sector, the development of new technologies such as microturbines and fuel cells is making distributed generation an increasingly attractive option. Installations of distributed generators by electricity producers are expected to total less than 50 megawatts in size and to be located near load centers. Although electricity supplied by distributed generation in the residential and commercial sectors is projected to increase by more than 50 percent over the forecast period, in 2020 it still is expected to account for less than 1 percent of electricity requirements in those sectors. Distributed generation provided 22 percent of the electricity used in the industrial sector in 1999, and that share is projected to increase to 23 percent by 2020, given the economic incentives in the projections.

### *Electricity Generation Sector*

Distributed generators are relatively small units that can be used to provide electricity when and where it is needed. For example, they can be connected to an electric utility's distribution system to reduce bottlenecks and increase the reliability of electricity supply. Unlike central station generators, which are capital-intensive and may require construction lead times of several years, distributed generators can be put in place quickly. In some cases they can even be moved to different sites as needed.

There is considerable interest among electricity generators in the potential use of distributed generators to cut costs by delaying, reducing, or eliminating investments in transmission and distribution equipment. In addition, the operational flexibility of distributed generators, which can either be connected to the grid or used in remote locations [*40*], may provide new system management options not available with central station units. Technologies used for distributed generation include diesel engines, internal combustion engines, microturbines, fuel cells, and renewable technologies such as wind and photovoltaic generators.

It is not clear how the opening of electricity markets to competition will affect the prospects for distributed generation in the electricity sector. There is considerable uncertainty about prices that would be paid for power from distributed generators when electricity generation services are opened to competition, because the rules have yet to be established in all these markets. There are also questions about the ability of the natural gas industry to supply small generators on a reliable basis and the prices that would be charged. In addition, current planning studies may understate or overstate the potential benefits to utilities and other large power suppliers, because there is little operational experience to draw from. Finally, the future treatment of distributed resources by the regulatory authorities that establish rules and pricing methods for transmission and distribution services is uncertain.

In *AEO2001*, distributed technologies are expected to penetrate in electricity markets when their costs are less than the combined costs of traditional baseload generation and the upgrades or expansions of the transmission and distribution infrastructure that would be needed to meet growth in demand. Two generic distributed technologies are included in the *AEO2001* model: peaking capacity, which has relatively high operating costs and is operated when demand levels are at their highest [*41*], and baseload capacity, which is operated on a continuous basis under a variety of demand levels [*42*]. Table 9 shows the assumed costs for the two generic technologies in 2000 and 2010. The assumed capital costs for the baseload generator are about 27 percent higher than those for the peaking generator in 2010, but its operations and maintenance costs are lower.

***Table 9. Cost and performance of generic distributed generators***

| Characteristic | Generic peaking 2000 | Generic peaking 2010 | Generic baseload 2000 | Generic baseload 2010 |
|---|---|---|---|---|
| Typical size (megawatts) | 0.4 | 0.4 | 2.5 | 1.6 |
| Construction lead time (years) | 0.2 | 0.2 | 0.5 | 0.5 |
| Overnight costs (1999 dollars per kilowatt) | | | | |
| Initial versions | — | 700 | — | 2,000 |
| Mature versions | 531 | 440 | 591 | 560 |
| Operating and maintenance costs | | | | |
| Variable (1999 mills per kilowatthour) | 23.0 | 15.5 | 15.0 | 10.4 |
| Fixed (1999 dollars per kilowatt per year) | 12.5 | 12.5 | 4.0 | 6.3 |
| Heat rate (Btu per kilowatthour) | 10,620 | 10,500 | 10,991 | 9,210 |

In the reference case, electricity producers are projected to add distributed generation capability only to meet peak demands. The first distributed generators are projected to be connected to the grid beginning in 2003, with total capacity reaching about 6 gigawatts in 2010 and 13 gigawatts in 2020. The added capacity is projected to contribute about 3 billion kilowatthours of generation during peak periods in 2010 and about 6 billion kilowatthours in 2020. The modest levels of generation projected represent an average capacity factor of about 5 percent for peaking distributed generators. In contrast, the higher assumed operating costs for generic baseload distributed generators keep them from being competitive with central station generators in the forecast. As a result, no baseload capacity is projected to be built through 2020 in the reference case.

### *Buildings Sector*

In the residential and commercial sectors, distributed generators installed by customers may supply either electricity alone (generation) or electricity as well as heat or steam (cogeneration or combined heat and power). On-site generators can have several advantages for electricity customers:

- If redundant capability is installed, reliability can be much higher than for grid-supplied electricity.
- Although electricity from distributed generation is generally more costly than grid-supplied power, the waste heat from on-site generation can be captured and used to offset energy requirements and costs for other end uses, such as space heating and water heating.
- Distributed generation can reduce the need for energy purchases during periods of peak demand, which can lower both current energy bills and, presumably, future energy bills when peak prices for electricity in competitive markets will be set by the most expensive generator supplying power to the grid.

Currently, very little residential capacity for electricity generation exists. Existing capacity consists primarily of emergency backup generators to provide electricity for minimum basic needs in the event of power outages. There are also a limited number of photovoltaic solar systems in a few niche markets with very high electricity rates and/or subsidies that encourage the use of renewable energy sources. Generating capacity in the commercial sector is also primarily for emergency backup; however, some electricity supply and peak generation is reported. EIA's 1995 Commercial Buildings Energy Consumption Survey (CBECS) estimated that about 0.05 percent of all commercial buildings (0.23 percent of all commercial floorspace) use generators for purposes other than emergency backup.

The *AEO2001* buildings models characterize several distributed generation technologies—either combined heat and power applications or pure generation—including conventional oil or gas engines and combustion turbines as well as such new technologies as photovoltaics, fuel cells, and microturbines. Photovoltaics are the most costly of the distributed technologies for buildings on the basis of installed capital costs; however, once photovoltaic systems are installed, no fuel costs are incurred. Petroleum-based generation is often used for emergency power backup in the commercial sector, but because of potential localized emissions issues it is less appropriate for continuous operation than is natural-gas-based generation. In the projections, the key growth technologies for cogeneration in the buildings sector are photovoltaics and natural-gas-fired generators.

The projected penetration rates of distributed generation technologies in the buildings sector are based either on forecasts of the economic returns from their purchase or on estimated participation in programs aimed at fostering distributed generation. Program-related purchases are based on estimates from the Department of Energy's Million Solar Roofs program and the Department of Defense fuel cell demonstration program [*43*].

Table 10 shows projected equipment costs and electrical conversion efficiencies for several of the distributed generation technologies characterized in the buildings sector models. The greatest cost declines are projected for the emerging technologies—photovoltaics, fuel cells, and microturbines. In addition, conversion efficiencies are projected to show the greatest improvement for fuel cells, reflecting the technical progress expected for this emerging technology. Because technology learning is expected to occur for photovoltaics, fuel cells, and microturbines, the data in Table 10 represent price ceilings for those three technologies; their actual costs could be lower if total cumulative shipments reach sufficiently high levels [*44*].

The reference case projects an increase of 56 percent in electricity supplied by distributed generation in the buildings sector. Distributed generation is estimated to account for approximately 0.3 percent of the sector's total electricity supply in 2000, rising to

***Table 10. Projected installed costs (1999 dollars per kilowatt) and electrical conversion efficiencies (percent) for distributed generation technologies by year of introduction and technology, 2000-2020***

| Year | Photo-voltaics | Fuel cell | Gas turbine | Gas engine | Gas micro-turbine |
|---|---|---|---|---|---|
| 2000-2004 | | | | | |
| Cost | 7,870 | 3,282 | 1,555 | 1,320 | 1,785 |
| Efficiency | 14 | 38 | 22 | 29 | 27 |
| 2005-2009 | | | | | |
| Cost | 6,700 | 2,834 | 1,503 | 1,240 | 1,574 |
| Efficiency | 16 | 40 | 24 | 29 | 29 |
| 2010-2014 | | | | | |
| Cost | 5,529 | 2,329 | 1,444 | 1,150 | 1,337 |
| Efficiency | 18 | 43 | 25 | 30 | 31 |
| 2015-2020 | | | | | |
| Cost | 4,158 | 1,713 | 1,373 | 990 | 1,047 |
| Efficiency | 20 | 47 | 27 | 30 | 34 |

0.4 percent in 2020. Figure 24 shows the projections for individual technologies.

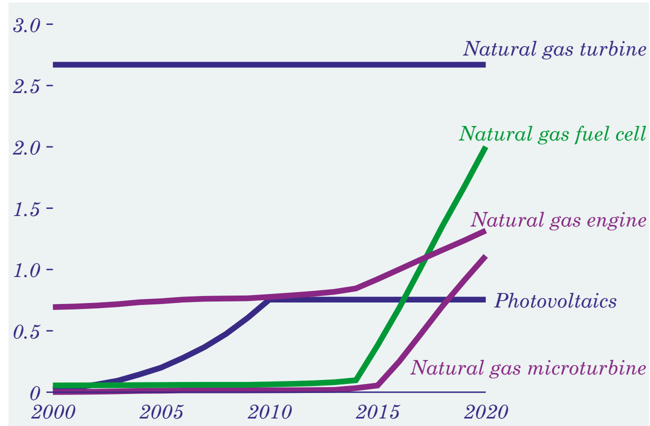
Natural gas turbines are viewed as a "mature" technology that remains static in the forecast. Even so, it maintains the largest share gained by a single technology throughout the period. The shares for other natural-gas-based technologies are projected to grow. This projected growth results from the combined effects of more rapid cost declines than those projected for turbines and increases in generation efficiency increase their market penetration. The combined effect of these two factors is especially important for fuel cell and microturbine technologies, which are currently in the early phases of commercialization for buildings-based applications. By the end of the projection period, fuel cells and microturbines combined are expected to overtake natural gas turbines in terms of total generation. Continued cost declines are also projected for photovoltaics, but the costs are expected to remain significantly higher than those of the other technologies available, and little additional penetration is projected after 2010, when current incentive programs are scheduled to end. Other technologies not shown in Figure 24—including municipal solid waste, hydropower, biomass, coal, and petroleum-based applications—are not widely applicable in the buildings sector or are limited by environmental concerns and therefore do not increase [*45*].

### *Industrial Sector Cogeneration*

Cogeneration systems, also called combined heat and power systems, simultaneously produce electricity or mechanical power and recover waste heat for use in other applications. The degree to which they are used for electricity production versus steam or heat production for other uses varies from facility to facility. Cogeneration systems can substantially reduce the energy losses that occur when electricity and process steam are produced independently. Conventional central station generation averages less than 33 percent delivered efficiency, whereas current cogeneration systems can deliver energy with efficiencies exceeding 80 percent.

The economic incentive to install cogeneration systems is based on the potential reduction in total operating costs. Cogeneration systems typically are most economical where steam loads are large and relatively continuous. Those industries that historically have been large users of cogeneration usually have had access to low-cost fuels, such as byproducts from industrial production processes. About two-thirds of current capacity is concentrated in the pulp and paper, chemical, and refining industries [*46*]. Over the past several years, technology developments have increased the range of sites where cogeneration may be an economical option. The most appropriate technology for a specific site or application depends on many factors: the steam load, fuel and electricity prices, on-site electricity demand, duty cycles, space constraints, emissions regulations, and interconnection issues.

***Figure 24. Projected buildings sector electricity generation by selected distributed resources in the reference case, 2000-2020 (billion kilowatthours)***




Additions of natural-gas-fired systems and biomass systems are evaluated separately in *AEO2001*. Eight natural-gas-fired cogeneration systems, ranging in size from 800 kilowatts to 100,000 kilowatts, are assumed to be available in the *AEO2001* model. Table 11 summarizes their key cost characteristics and assumed cost improvement over time. Because biomass-based cogeneration is assumed to be added in the industrial sector in response to projected increases in biomass consumption in the sector, installation costs are not explicitly considered. Because most of the expected increase in biomass consumption is concentrated in the pulp and paper

***Table 11. Costs of industrial cogeneration systems, 1999 and 2020***

| System | Size (megawatts) | Installed cost (1999 dollars per kilowatt) 1999 | Installed cost (1999 dollars per kilowatt) 2020 | Operating and maintenance costs (1999 cents per kilowatthour) 1999 | Operating and maintenance costs (1999 cents per kilowatthour) 2020 |
|---|---|---|---|---|---|
| Engine | 0.8 | 975 | 690 | 1.07 | 0.90 |
| | 3 | 850 | 710 | 1.03 | 0.90 |
| Gas turbine | 1 | 1,600 | 1,340 | 0.96 | 0.80 |
| | 5 | 1,075 | 950 | 0.59 | 0.49 |
| | 10 | 965 | 830 | 0.55 | 0.46 |
| | 25 | 770 | 675 | 0.49 | 0.43 |
| | 40 | 700 | 625 | 0.42 | 0.40 |
| Combined cycle | 100 | 690 | 620 | 0.36 | 0.30 |

industry, which is one of the largest cogeneration industries, it is assumed that 90 percent of the projected increase in biomass consumption will be used to cogenerate electricity.

Figure 25 shows the projected composition of cogeneration capacity by fuel in 2020. Natural gas accounts for most of the projected change in total capacity, followed by biomass. Natural-gas-fired cogeneration capacity in the industrial sector is projected to increase by 18.7 gigawatts from 1999 to 2020, and biomass-fired capacity is projected to increase by 3.5 gigawatts. About 70 percent of the new capacity is expected to be added in the paper and chemical industries. There is assumed to be little growth in cogeneration capacity for other fuels between 1999 and 2020, because coal systems cost significantly more than gas turbine systems and, given their relatively large minimum economical size, are subject to more stringent environmental requirements.

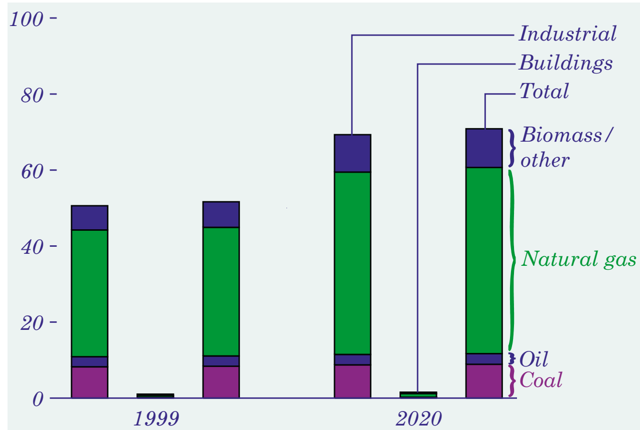
The difference between the delivered prices of electricity and natural gas in the industrial sector is a key component in the economics of cogeneration systems. A larger difference increases the economic incentives for cogeneration, and a smaller difference reduces them. Therefore, in the *AEO2001* reference case, the narrowing difference between electricity and natural gas prices projected over the forecast period reduces the economic incentive to invest in cogeneration systems.

In summary, total distributed generation capacity is projected to grow more rapidly than electricity sales in the forecast, averaging about 2.5 percent annually. When projected additions in the electricity generation sector are excluded, the remainder of the expected capacity growth is slightly less than the projected growth in electricity sales. Given the projections for falling electricity prices and rising natural gas prices, however, this still represents a robust outlook.

## Restructuring of State Retail Markets for Electricity

Since May 1996, a number of States have passed legislation mandating the restructuring of their retail electricity industries. Restructuring legislation has focused primarily on deregulating the electricity supply sector to allow retail electricity customers access to competitive energy suppliers. Some States have also granted competitive retail access to components of distribution service, such as billing and meter reading [*47*]. Most of the States that have authorized competitive retail access to electricity have historically had higher electricity prices than the national average.

***Figure 25. Cogeneration capacity by type and fuel, 1999 and 2020 (gigawatts)***




As of September 2000, 24 States and the District of Columbia, representing 55 percent of U.S. electricity sales [*48*], have mandated electric industry restructuring. Two States, Alaska and South Carolina, have legislation pending. Virtually all the other States have considered restructuring. Many are waiting to see how deregulated markets will affect electricity prices in the States that have already implemented restructuring legislation before making a decision. Some State utility regulatory bodies have established frameworks for deregulation and are negotiating terms with utilities and potential competitive electricity suppliers that will be implemented in the event that restructuring legislation passes.

### *Issues of Price Stability and Service Reliability in Deregulated Electricity Markets*

In the States that have passed restructuring legislation, settlement negotiations with electricity producers and consumers have raised a number of contentious issues, including market power, stranded cost recovery and securitization, generation asset divestiture, environmental concerns, customer education and attitudes toward restructuring, consumer protection, regulation of affiliate transactions, price stability, and service reliability. Ultimately, the resolution of such issues will determine the rate at which restructured electricity markets become competitive and how customers, utilities and their stockholders, competitive suppliers, and other stakeholders will be affected.

Over the past year, as a result of major regional outages and rising fuel prices, the issues of price stability and service reliability have been of particular concern nationwide. Many observers and participants in restructuring negotiations have raised concerns that electricity customers, especially residents and small businesses, could experience higher prices and less reliable service as a result of deregulation. Fears of higher prices have been fueled by concerns that a competitive market could take a long time to develop. In an underdeveloped market, incumbent utilities or large corporations could gain most of the market share, leaving them free to raise prices at will in the absence of regulation.

In States where competition is underway, it has mostly been the large commercial and industrial consumers who have been courted by competitive energy suppliers. Consequently, all States that have mandated restructuring, or allowed it to proceed, have also mandated price reductions and/or price freezes for residential and small commercial customers for the duration of a negotiated "transition period." The transition period is the estimated number of years that it will take to realize a fully competitive electricity supply market. As discussed below, *AEO2001* incorporates State-mandated price freezes and reductions into its forecasts of energy prices.

Service reliability has also become a concern as utilities have downsized their work forces in preparation for the switch to a competitive marketplace. In addition, although the demand for electricity has been increasing, utilities have been reluctant to make expensive additions to generation and transmission capacity, because their ability to recover the costs remains uncertain as States consider whether and/or how to carry out restructuring of the industry. A recent EIA study [*49*] indicates that constraints on inter- and intraregional electricity transmission capacity could affect the ability of electricity markets to respond quickly and efficiently to changing demand conditions.

Concerns about prices and reliability were heightened when outages and price spikes hit the Midwest region during the summer of 1998, and to a lesser extent, by outages and price spikes around the country during the summer of 1999. More recently, price spikes in New England during the winter of 2000 and outages and price spikes in wholesale and retail electricity markets in California throughout the summer of 2000 have been seen as an indication of potential problems.

The U.S. Department of Energy's Power Outage Study Team [*50*] has studied the major outages and voltage depressions that occurred around the country in the summer of 1999, finding in general that the "necessary operating practices, regulatory policies, and technological tools for assuring an acceptable level of reliability were not yet in place." However, price spikes in the Midwest in 1999 were not as sustained as those in the summer of 1998, and the consequences were not as severe, pointing to a maturing competitive electricity market in that region [*51*]. The 1999 price spikes did not prompt the level of anxiety over the increasingly competitive electricity market as had the Midwest price spikes of the previous year [*52*], and in 2000, with more generating capacity on line and a cooler summer, the Midwest electricity market remained calm.

Separate, independent investigations into the functioning of competitive wholesale electricity markets in New England and California have found market design and operational flaws in both regions [*53*]. Both studies found that market structures may have encouraged traders or generators to bid up prices by "gaming the system" [*54*]. The two regions are now in the process of trying to redesign aspects of their competitive markets. ISO New England investigated the NEPOOL Installed Capacity (ICAP) market after the January 2000 price spikes and found that it was too flawed to be fixed. ISO New England then filed a request with the FERC in May 2000 that the ICAP market be eliminated and that the ISO begin a collaborative effort with NEPOOL participants to develop viable market-driven alternatives to the ICAP market [*55*].

In California, Governor Gray Davis directed the Electricity Oversight Board and the California Public Utilities Commission to investigate the circumstances contributing to the outages and price spikes during the summer of 2000 [*56*]. After the study found serious market flaws, Governor Davis called on FERC to investigate the wholesale markets and intervene to ensure that "a workably competitive market exists before California consumers and California's economy are subjected to unconstrained, market-based electricity prices" [*57*].

### *Market Effects of High Natural Gas Prices*

High natural gas prices in 2000 have also concerned stakeholders in the process of electricity industry deregulation. With new gas turbines increasingly being used as the marginal units of electricity production, higher gas prices will theoretically increase electricity prices more in competitive electricity supply markets with marginal cost pricing than in regulated markets with prices based on average costs.

Although the demand for natural gas has been increasing, low gas prices in 1998 and 1999 curtailed gas drilling in 1999. In 2000, flat production, increased demand, and lower then average stock levels resulted in higher natural gas prices. Still, according to a recent analysis of supply and demand in the gas industry [*58*], although drilling has increased substantially, a 6- to 18-month lag is anticipated before much additional production will be brought on line.

With an expanding economy and an increase in planned construction of new gas turbines, future demand for natural gas is expected to increase regardless of whether the coming winters will be warm or cold. In States with newly deregulated retail electricity markets, mandated price freezes and reductions during the transition to competition are expected to keep electricity prices from increasing excessively with rising gas prices [*59*]. Electricity price increases in other States as a result of higher gas prices may depend on several factors, including the political influence of electricity users and utilities; economic hardships caused by price increases on particular users; the effects of electricity price increases on local economies; and perceptions by some utilities that large increases in electricity prices may cause them to lose support for their positions in restructuring negotiations.

### *AEO2001* Assumptions

*AEO2001* represents 13 electricity supply regions, based on North American Electric Reliability Council (NERC) regions and subregions. When all the electricity sales in a supply region [*60*] come from deregulated States, the region is assumed to be fully competitive. When a majority of electricity sales (but not all) within a region come from deregulated States, the region is assumed to be partially competitive. Within a partially competitive region, *AEO2001* assumes the same percentages of competitive and regulated pricing as the percentages of electricity sales in that region's deregulated and regulated States, respectively. Fully or partially competitive regions include the New England, New York, Mid-Atlantic, East Central (Illinois), Rocky Mountain Power Area, California, and the Southwest Power Pool electricity supply regions.

In *AEO2000*, the Southwest Power Pool was assumed to be a noncompetitive region, with only 32 percent of its sales coming from States that had mandated deregulation. In the past year, however, Entergy, a very large utility supplying about 100 million megawatthours of electricity to 2.5 million customers in several States, left the Southwest Power Pool to join the Southeastern Electric Reliability Council. The huge loss of mostly noncompetitive energy sales increased the share of competitive electricity sales in the Southwest Power Pool to 54 percent, making it a competitive region in *AEO2001*. Electricity prices in the Northwest, Mid-Continent, Southeast, and Florida regions still are assumed to be regulated.

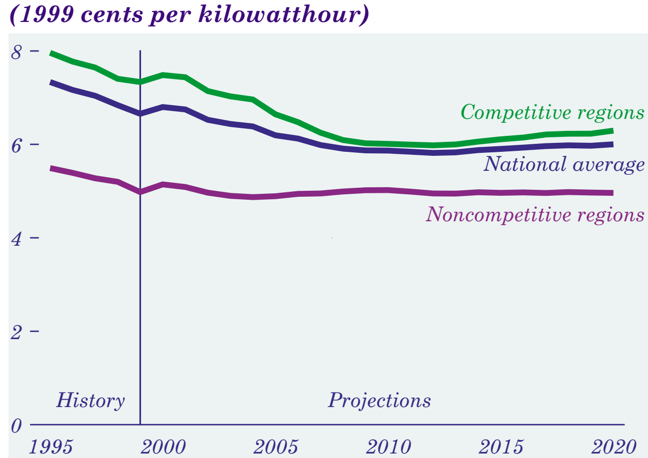
*AEO2001* assumes a gradual, 10-year transition to fully competitive pricing from the inception of deregulation in competitive regions, with the 10-year period varying by region. This is the estimated amount of time needed to free the changing industry of the anticompetitive effects of stranded costs, negative customer attitudes toward choosing electricity service providers, and imperfect market structures. It also accounts for the time needed for an adequate number of suppliers to enter the market and learn to be sufficiently cost-efficient to stay in the market and keep it competitive.

### *AEO2001* Electricity Price Forecasts

*AEO2001* forecasts a decline of 1 cent per kilowatthour in the average national electricity price between 2000 and 2012, followed by a slight increase of 0.2 cent per kilowatthour through 2020 (Figure 26). In general, price differences among regions are projected to be greatly reduced—from 7.0 cents per kilowatthour between the highest (New York) and lowest (Northwest) in 1995 to 3.8 cents per kilowatthour between the highest (New York) and lowest (Northwest) in 2020.

Figure 26 shows historical and projected average electricity prices paid by end users in competitive and noncompetitive regions compared with national

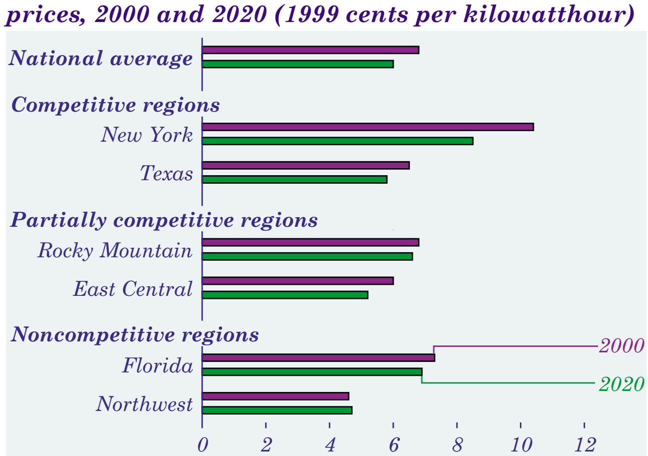
***Figure 26. Average annual electricity prices for competitive and noncompetitive regions, 1995-2020 (1999 cents per kilowatthour)***



average prices. Most of the States that have authorized competitive retail access to electricity have historically experienced electricity prices that are higher than the national average, mainly as a result of higher than average regional capital costs (the material and labor costs of building power plants). The competitive regions as a group also have a higher concentration of older oil- and gas-fired steam generators that require more maintenance than other types of plants, as well as higher labor costs associated with operations and maintenance, than the noncompetitive regions. For example, in the Southeast and Mid-Continent regions, which are assumed to be noncompetitive, reliance on older coal-fired generators, for which the capital costs have largely been paid, provide a plentiful source of electricity with lower associated maintenance costs, resulting in lower electricity prices. The labor costs associated with plant operation and maintenance are also relatively low in those regions. The Northwest, another noncompetitive area, has access to abundant hydroelectric power sources at very low cost.

Figure 27 shows expected regional price changes between 2000 and 2020 for selected regions with competitive, partially competitive, and noncompetitive electricity supply. By region, the largest declines in electricity prices are projected for the four regions that currently have the highest average electricity prices: California, New England, New York, and the Mid-Atlantic. These were the first regions in which State restructuring laws were implemented, and they have already experienced price drops between 0.5 and 1.5 cents per kilowatthour since 1995. In the reference case, they are expected to see further declines averaging about 2.5 cents per kilowatthour from 2000 to 2010.

*Figure 27. Projected average regional electricity prices, 2000 and 2020 (1999 cents per kilowatthour)*




Three other regions (East Central, Texas, and Mid-America) are projected to see price declines between 1.5 cents per kilowatthour (in Texas, a fully competitive region) and just over 0.5 cent per kilowatthour (in Mid-America, the least competitive of the three regions) from 2000 to 2010. After the decreases, prices in the East Central and Mid-American regions are expected to increase slightly (about 1 mill per kilowatthour) by 2020. Prices in Texas by 2020 are projected to regain up to half the decrease expected by 2020 as a result of additions of new power plants fueled by increasingly expensive natural gas.

The Mid-Continent, Florida, and Southeast regions are expected to experience very small price declines (from a few mills per kilowatthour in the Southeast to just over 0.5 cent per kilowatthour in Florida) over the next several years, even though they are noncompetitive regions. In Florida, expensive oil plants are being replaced by cheaper coal and gas plants, helping to bring fuel costs down. In the Mid-Continent region, an expected decrease in capital costs is expected to bring prices down as plants are run at higher capacity. In the Southeast region, plant operations and maintenance costs are expected to decline slightly as a result of additions of fossil-fired steam plants in previous years. After 2005, prices in these regions are expected to remain relatively steady through 2020.

The Northwest and Southwest are the two lowest-priced electricity supply regions in the Nation. Prices in the Northwest, a noncompetitive region, are projected to remain relatively steady through 2020. The Southwest is expected to see price increases through 2020 as a result of competition and the costs of expected additions of new generating capacity, most of which are projected to be fueled by natural gas.

Although average electricity prices for the competitive regions are expected to drop to just 1 mill per kilowatthour above the national average by 2010, they remain 1 cent per kilowatthour above the average prices for the noncompetitive regions in the forecast, for the reasons discussed above. Nationally, average electricity prices are expected to fall as the capital costs for some more expensive plants are paid off, newer plants are built with lower associated maintenance costs, and competition (as well as new regulation) forces electricity suppliers to become more efficient. Competitive regions still are expected to have higher resources and labor costs associated with building, maintaining, and fueling generators than are the noncompetitive regions. As a result, after 2010, the expected surge in new additions of natural-gas-fired generators, combined with rising natural gas prices, is expected to increase prices by a little more in the competitive regions than in the noncompetitive regions.

## Carbon Dioxide Emissions in *AEO2001*

### *Reference Case*

In the *AEO2001* reference case, carbon dioxide emissions from energy consumption are expected to reach 1,809 million metric tons carbon equivalent in 2010, continuing to rise to 2,041 million metric tons carbon equivalent in 2020 (Figure 28), an average annual growth rate of 1.4 percent between 1999 and 2020. The projections for 2010 and 2020 are 34 percent and 51 percent higher, respectively, than the 1990 level of 1,349 million metric tons carbon equivalent.

Carbon dioxide emissions are projected to increase throughout the forecast, because continued economic growth and moderate increases or even decreases in projected real energy prices are expected to lead to increasing energy consumption. The 1.4-percent growth rate for projected carbon dioxide emissions is slightly faster than the growth rate for total energy consumption, which is expected to increase at an average annual rate of 1.3 percent. The growth in carbon dioxide emissions is projected to be more rapid than the growth in total energy consumption for two primary reasons. First, approximately 27 percent of existing nuclear generating capacity, which emits no carbon dioxide, is expected to be retired by 2020, and no new nuclear plants are projected to be constructed. Second, because prices for both natural gas and coal are expected to remain moderate, growth in the use of renewable energy sources is projected to remain slow.

Through 2020, the demand for energy services, such as travel, household appliances, and commercial equipment, is projected to continue to increase. As a result, projected energy consumption per person and carbon dioxide emissions per person in 2020 are higher than they were in 1999. Between 1999 and 2020, carbon dioxide emissions per person are projected to increase from 5.5 metric tons carbon equivalent to 6.3 metric tons carbon equivalent, an average annual growth rate of 0.6 percent (Figure 29).

Total energy intensity in the U.S. economy, measured as energy consumption per dollar of GDP is expected to show a decrease through 2020, resulting from the penetration of more efficient energy-using equipment into the capital stock. Total energy intensity is projected to fall from 10.8 thousand Btu per dollar of GDP in 1999 to 7.7 thousand Btu per dollar of GDP in 2020, an average decline of 1.6 percent annually. Because carbon dioxide emissions are projected to grow more rapidly than energy consumption, however, carbon dioxide emissions per dollar of GDP are projected to decrease at a slower rate than energy intensity. Between 1999 and 2020, carbon dioxide emissions are estimated to decline from 170 to 124 metric tons carbon equivalent per million dollars of GDP, an average annual decline of 1.5 percent (Figure 30).

### *Comparisons with AEO2000 Projections*

In *AEO2001*, projected carbon dioxide emissions in 2020 are 2,041 million metric tons carbon equivalent, 3.1 percent higher than projected in *AEO2000*.

***Figure 28. Projected U.S. carbon dioxide emissions by sector and fuel, 1990-2020 (million metric tons carbon equivalent)***

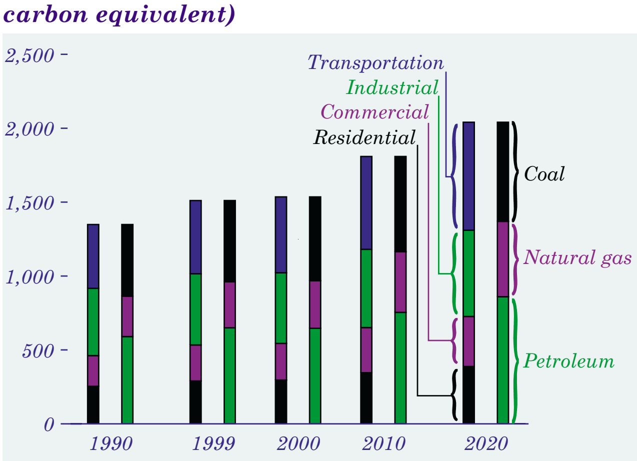



***Figure 29. U.S. carbon dioxide emissions per capita, 1990-2020 (metric tons carbon equivalent per person)***

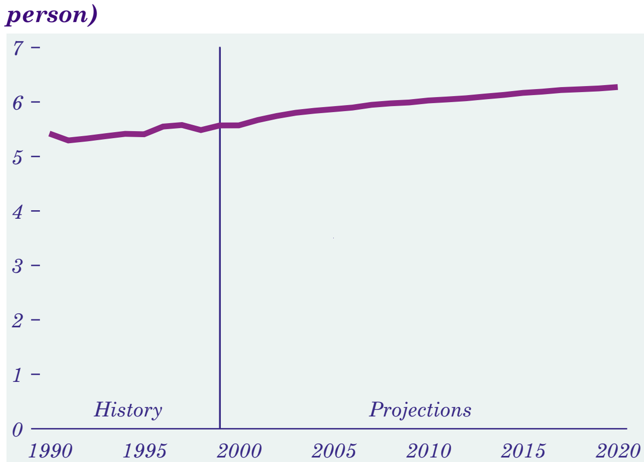
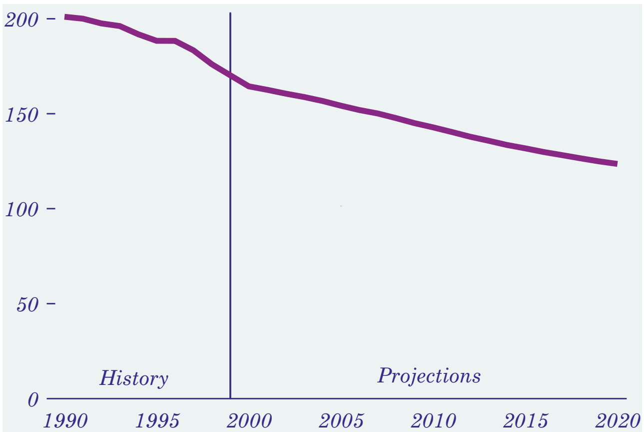


*Figure 30. U.S. carbon dioxide emissions per unit of gross domestic product, 1990-2020 (metric tons carbon equivalent per million dollars)*




Carbon dioxide emissions are expected to reach a higher level primarily as a result of more rapid projected economic growth in the *AEO2001* reference case. Over the projection period, GDP is expected to increase at an average annual rate of 3.0 percent, compared with the 2.1-percent yearly GDP growth projected in *AEO2000*. The higher economic growth projection in *AEO2001* results in part from statistical and definitional changes in the National Income and Product Accounts, as discussed earlier in "Issues in Focus" (see page 22). In addition, the economic forecast reflects a more optimistic view of long-run economic growth, leading to higher projections for industrial output, housing starts, growth in commercial floorspace, and disposable income, all of which contribute to higher projected growth in the demand for energy services and in energy consumption. As a result, projected energy consumption in 2020 is higher in all end-use sectors in *AEO2001* than in *AEO2000*.

The *AEO2001* projection for the number of U.S. households in 2020 is 1.5 percent higher than was projected in *AEO2000*, with most of the increase being in single-family homes. The total number of U.S. households is expected to increase from 104.1 million in 1999 to 129.4 million in 2020. In addition, *AEO2001* projects that the average size of new homes will increase through 2020, whereas *AEO2000* assumed no growth in the size of new homes. In the commercial sector, the *AEO2001* projection for total floorspace in 2020 is 11.0 percent higher than the *AEO2000* projection as a result of the higher projected economic growth. In addition, *AEO2001* projects more rapid growth in electricity consumption in both the residential and commercial sectors for personal computers, office equipment, and a variety of miscellaneous uses consistent with recent trends.

Overall energy intensity in the residential and commercial sectors is also expected to be higher in *AEO2001* than was projected in *AEO2000*. In the residential sector, total energy consumption per square foot is projected to decrease at an average annual rate of 0.1 percent through 2020, as compared with a projected 0.2-percent decline in *AEO2000*. In addition, because the size of new homes is expected to increase, energy consumption per household is projected to increase by 0.1 percent annually, in contrast to the 0.1-percent annual decrease projected in *AEO2000*. Total residential carbon dioxide emissions, including emissions from the generation of electricity used in the sector, are projected to be 10 million metric tons carbon equivalent (2.8 percent) higher in 2020 than was projected in *AEO2000*. In the commercial sector, total energy consumption per square foot is projected to increase at an average annual rate of 0.1 percent through 2020 in *AEO2001*, as compared with the 0.1-percent decrease projected in *AEO2000*. Higher projected energy intensity combined with higher projected floorspace results in a projection of carbon dioxide emissions in 2020 that is 31 million metric tons carbon equivalent (10.1 percent) higher than the *AEO2000* projection.

Along with higher projected economic growth, industrial output in *AEO2001* is projected to grow at an average annual rate of 2.6 percent through 2020, compared with 1.9 percent in *AEO2000*. Most of the difference, however, is in non-energy-intensive manufacturing, which is expected to grow at a far more rapid pace than energy-intensive manufacturing or nonmanufacturing activity. In addition, the *AEO2001* projections include a more optimistic assessment of the potential for efficiency improvements in the industrial sector consistent with recent trends. Energy intensity in the industrial sector is expected to decline at an average annual rate of 1.5 percent in *AEO2001*, compared with a projected average annual decline of 0.9 percent in *AEO2000*. As a result, with the carbon dioxide emissions associated with industrial electricity use also expected to be lower, the *AEO2001* projection for industrial sector carbon dioxide emissions in 2020 is essentially the same as the *AEO2000* projection.

In the transportation sector, the higher projections for economic growth and disposable income in *AEO2001* lead to higher projections for light-duty vehicle travel and for freight travel by truck, rail, and ship than in *AEO2000*. However, the average efficiency of new light-duty vehicles in 2020 is expected to be higher than was projected in *AEO2000*, due to recent industry developments—28.0 miles per gallon compared with 26.5 miles per gallon in *AEO2000*. Higher efficiency is also projected for freight trucks, based on recent industry data. The potential for growth in air travel was also reevaluated for the *AEO2001* projections. As a result, the *AEO2001* projection for air travel in 2020 is 7.1 percent lower than the *AEO2000* projection. In total, however, transportation energy consumption is expected to increase more rapidly than in *AEO2000* (averaging 1.8 percent as compared with 1.7 percent per year), and carbon dioxide emissions from the transportation sector in 2020 are expected to be higher by 21 million metric tons carbon equivalent, or 2.9 percent.

*AEO2000* projected that both electricity sales and carbon dioxide emissions from electricity generation (excluding cogeneration) would increase on average by 1.3 percent per year between 1999 and 2020. The *AEO2001* projections for electricity demand are higher, particularly for the residential and commercial sectors, as noted above. Purchased electricity demand is projected to increase at an average annual rate of 1.8 percent, and carbon dioxide emissions from electricity generation (excluding cogeneration) are projected to increase by an average of 1.6 percent per year. In *AEO2001*, less nuclear capacity is expected to be retired by 2020 than was projected in *AEO2000* as a result of lower assumed costs for extending the operating life of existing nuclear plants and higher projected prices for natural gas. In addition, coal consumption for electricity generation is expected to be slightly lower and natural gas consumption higher than projected in *AEO2000*.

### *Carbon Dioxide Emissions by Sector*

In 2020, electricity generation (excluding cogeneration) is expected to account for 38 percent of all carbon dioxide emissions, up from 37 percent in 1999. The increasing share of carbon dioxide emissions from generation results, in part, from the 1.8-percent annual growth rate in projected electricity consumption. New capacity will be required to meet the expected electricity demand growth and to replace the loss of some nuclear capacity that is expected to be retired. Of that new capacity, about 6 percent is projected to be fueled with coal and 92 percent with natural gas.

The growth of both projected energy consumption and carbon dioxide emissions in the transportation sector is faster than in the other end-use sectors because of projected increases in travel and the relatively slow improvement in fuel efficiency that is expected in the reference case. Between 1999 and 2020, transportation energy demand and carbon dioxide emissions are projected to grow at average annual rates of 1.8 percent, and in 2020 it is estimated that the transportation sector will account for 36 percent of all carbon dioxide emissions from energy use. The average efficiency of the light-duty vehicle fleet—cars, light trucks, vans, and sport utility vehicles—is projected to increase from 20.5 to 21.5 miles per gallon between 1999 and 2020. Over the same period, vehicle-miles traveled by light-duty vehicles are expected to increase by 1.9 percent per year, faster than the expected growth rate for the over-age-16 population (0.9 percent per year). Growth in both air and freight truck travel, at average projected rates of 3.6 percent and 2.6 percent per year, also contributes to the expected growth in carbon dioxide emissions from the transportation sector.

Carbon dioxide emissions from the residential and commercial sectors are expected to grow by 1.4 percent and 1.6 percent per year, respectively, contributing 19 percent and 17 percent of carbon dioxide emissions in 2020, including the emissions from the generation of electricity used in each sector. The projected annual growth rates for energy consumption in the residential and commercial sectors are 1.2 percent and 1.4 percent, respectively. In both sectors, growth in energy consumption and carbon dioxide emissions is expected to result from continued growth in energy service demand from an increasing number of households and commercial establishments, offset somewhat by efficiency improvements in both sectors.

Carbon dioxide emissions from the industrial sector are expected to increase by 0.9 percent per year through 2020, accounting for 29 percent of the total projected carbon dioxide emissions in 2020, including emissions from electricity generation for the sector. Total industrial energy consumption is projected to grow at an average annual rate of 1.0 percent. The relatively low expected growth rate as compared with other sectors results from efficiency improvements, slow growth in coal use for boiler fuel, and a shift to less energy-intensive industries. Energy use per unit of output is expected to decline as additions to the capital stock are made from increasingly efficient equipment and investments are made to improve the efficiency of the existing stock. The use of renewable energy sources in the industrial sector is also projected to increase at a faster rate than is projected for energy markets as a whole. Approximately 90 percent of the projected growth in renewable energy consumption in the industrial sector is for cogeneration and the remainder for boiler fuel.

### *Carbon Dioxide Emissions by Fuel*

By fuel, petroleum products are projected to be the leading source of energy-related carbon dioxide emissions because of the continuing growth expected in the transportation sector, where petroleum products currently account for some 97 percent of total energy use. About 42 percent of all U.S. carbon dioxide emissions—860 million metric tons carbon equivalent of the total of 2,041 million metric tons carbon equivalent in 2020—are projected to be from petroleum products. About 82 percent of the total carbon dioxide emissions from petroleum use are estimated to result from transportation uses in 2020.

Coal is expected to be the second leading source of carbon dioxide emissions in 2020 at 671 million metric tons carbon equivalent, or about 33 percent of total U.S. carbon dioxide emissions. Coal has the highest carbon content of all the fossil fuels and is expected to remain the predominant fuel source for electricity generation through 2020. By 2020, the coal-fired share of generation (excluding cogeneration) is expected to decline from its 1999 level of 54 percent to 47 percent. About 90 percent of carbon dioxide emissions from coal in 2020 are estimated to result from electricity generation.

Natural gas consumption for both electricity generation and direct end uses is expected to grow at the fastest rate of all the fossil fuels—an average of 2.3 percent per year through 2020. Natural gas has a relatively low carbon content relative to other fossil fuels (only about one-half that of coal), and thus carbon dioxide emissions from natural gas use are projected to be just 510 million metric tons carbon equivalent in 2020, about 25 percent of the total.

### *Macroeconomic Growth*

The assumed rate of economic growth has a strong impact on projections of energy consumption and, therefore, carbon dioxide emissions. In *AEO2001* the high economic growth case includes higher projected growth in population, the labor force, and labor productivity than in the reference case, leading to higher industrial output, lower inflation, and lower interest rates. As a result, projected GDP in the high economic growth case increases at an average rate of 3.5 percent per year from 1999 to 2020, compared with a projected growth rate of 3.0 percent per year in the reference case.

With higher projected economic growth, energy consumption is expected to grow at a faster rate, as higher projected manufacturing output and income increase the demand for energy services. Total energy consumption in the high economic growth case is estimated at 135.9 quadrillion Btu in 2020, compared with 127.0 quadrillion Btu in the reference case (Figure 31). As a result of the higher consumption, carbon dioxide emissions are projected to reach a level of 2,193 million metric tons carbon equivalent in 2020, 7 percent higher than the projected reference case level of 2,041 million metric tons carbon equivalent (Figure 32).

In the low economic growth case, assumptions of lower projected growth in population, the labor force, and labor productivity result in a projected average annual growth rate of 2.5 percent through 2020. With lower economic growth, estimated energy consumption in 2020 is reduced from 127.0 quadrillion Btu in the reference case to 119.0 quadrillion Btu, and carbon dioxide emissions in 2020 are estimated at 1,916 million metric tons carbon equivalent, 6 percent lower than in the reference case.

Total energy intensity, measured as primary energy consumption per dollar of GDP, is projected to improve at a more rapid rate in the high economic growth case than in the reference case, partially offsetting the changes in energy consumption caused by the higher growth assumptions. With more rapid projected growth in energy consumption, there is expected to be a greater opportunity to turn over and improve the stock of energy-using technologies, increasing the overall efficiency of the capital stock. Aggregate energy intensity in the high economic growth case is expected to decrease at a rate of 1.8 percent per year from 1999 through 2020, compared

***Figure 31. Projected U.S. energy consumption in three economic growth cases, 1990-2020 (quadrillion Btu)***

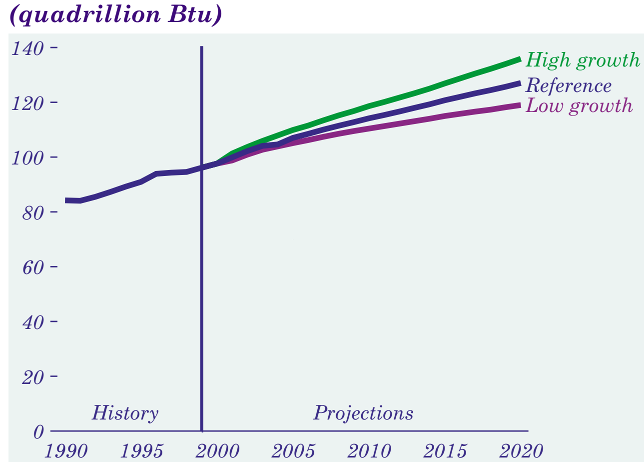


*Figure 32. Projected U.S. carbon dioxide emissions in three economic growth cases, 1990-2020 (million metric tons carbon equivalent)*

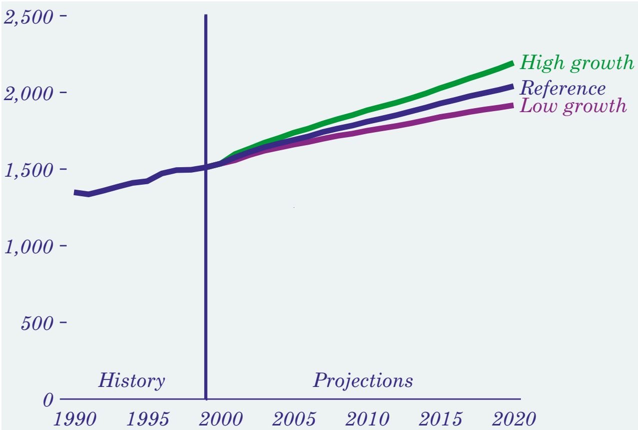
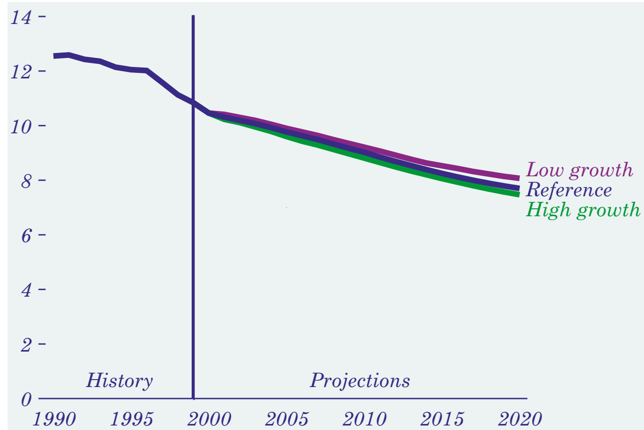



*Figure 33. Projected U.S. energy intensity in three economic growth cases, 1990-2020 (thousand Btu per dollar of GDP)*




with expected declines of 1.6 percent in the reference case and 1.4 percent in the low economic growth case (Figure 33).

### *Technology Improvement*

The *AEO2001* reference case assumes continued improvements in technology for both energy consumption and production; improvements in building shell efficiencies for both new and existing buildings; efficiency improvements for new appliances, industrial equipment, transportation vehicles, and generating equipment; productivity improvements for coal production; and improvements in the exploration and development costs, finding rates, and success rates for oil and gas production. As a result of the continued improvements in the efficiency of end-use and electricity generation technologies, total energy intensity in the reference case is projected to decline at an average annual rate of 1.6 percent between 1999 and 2020.

The projected decline in energy intensity is considerably less than that experienced during the 1970s and early 1980s, when energy intensity declined, on average, by 2.3 percent per year. Approximately 40 percent of that decline can be attributed to structural shifts in the economy—shifts to service industries and other less energy-intensive industries; however, the rest resulted from the use of more energy-efficient equipment. During those years there were periods of rapid escalation in energy prices, encouraging some of the efficiency improvements. Then, as energy prices moderated, the improvement in energy intensity moderated. Between 1986 and 1999, energy intensity declined at an average annual rate of 1.3 percent.

Regulatory programs have contributed to some of the past improvements in energy efficiency, including the Corporate Average Fuel Economy standards for light-duty vehicles and standards for motors and energy-using equipment in buildings in the Energy Policy Act of 1992 and the National Appliance Energy Conservation Act of 1987. In keeping with the general practice of incorporating only current policy and regulations, the reference case for *AEO2001* assumes no new efficiency standards. Only current standards or approved new standards with specified levels are included (see "Legislation and Regulations," page 18).

*AEO2001* presents a range of alternative cases that vary key assumptions about technology improvement and penetration. In the high technology case, a more rapid pace of technology improvements in energy-consuming equipment is projected to reduce energy consumption and energy-related carbon dioxide emissions to levels below those expected in the reference case. Conversely, a slower rate of improvement assumed in the low technology case is projected to result in higher consumption and emissions.

In the end-use demand sectors, experts in technology engineering were consulted to derive high technology assumptions, considering the potential impacts of increased research and development for more advanced technologies. The revised assumptions include earlier years of introduction, lower costs, higher maximum market potential, and higher efficiencies than assumed in the reference case. It is possible that even further technology improvements beyond those assumed in the high technology case could occur if there were a very aggressive research and development effort. For the electricity generation sector, the costs and efficiencies of advanced fossil-fired and new renewable generating technologies were assumed to improve from reference case values, based on assessments from the U.S. Department of Energy's Office of Energy Efficiency and Renewable Energy and Office of Fossil Energy and from the Electric Power Research Institute [*61*].

Although more advanced technologies may reduce energy consumption, in general they are more expensive when initially introduced. In order to penetrate into the market, advanced technologies must be purchased by consumers; however, many potential purchasers may not be willing to buy more expensive equipment that has a long period for recovering the additional cost through energy savings, and many may value other attributes over energy efficiency. Penetration can also be slowed by the relative turnover of the capital stock. In order to encourage more rapid penetration of advanced technologies, to reduce energy consumption or carbon dioxide emissions, it is likely that either market policies, such as higher energy prices, or nonmarket policies, such as new standards, may be required.

The 2001 technology case assumes that all future equipment choices will be made from the equipment and vehicles available in 2001, with new building shell and industrial plant efficiencies frozen at 2001 levels. New generating technologies are assumed not to improve over time. Aggregate efficiencies are assumed to improve over the forecast period as new equipment is chosen to replace older stock and the capital stock expands, and building shell efficiencies are assumed to improve as projected energy prices increase in the forecast.

In the high technology case, with the high technology assumptions for all four end-use demand sectors and the electricity generation sector combined, aggregate energy intensity is expected to decline at an average of 1.9 percent per year from 1999 to 2020, compared with 1.6 percent per year in the reference case (Figure 34). In the 2001 technology case, the average decline is expected to be only 1.4 percent per year through 2020. Total energy consumption is projected to increase to 118.9 quadrillion Btu in 2020 in the high technology case, compared with 127.0 quadrillion Btu in the reference case and 133.3 quadrillion Btu in the 2001 technology case (Figure 35).

The lower projected energy consumption in the high technology case lowers the projection for carbon dioxide emissions from 2,041 million metric tons carbon equivalent in the reference case in 2020 to 1,875 million metric tons carbon equivalent (Figure 36). In the 2001 technology case, projected carbon dioxide emissions increase to 2,157 million metric tons carbon equivalent in 2020.

***Figure 34. Projected U.S. energy intensity in three technology cases, 1990-2020 (thousand Btu per dollar of GDP)***

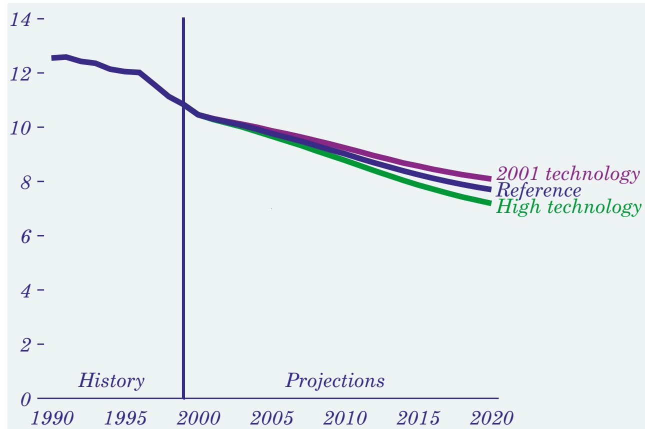
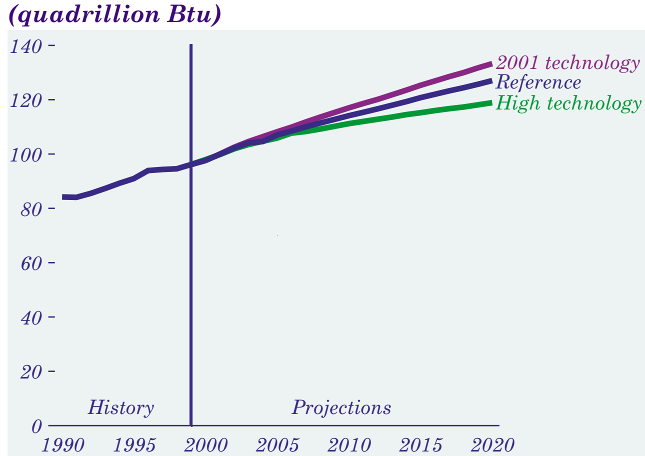



***Figure 35. Projected U.S. energy consumption in three technology cases, 1990-2020 (quadrillion Btu)***



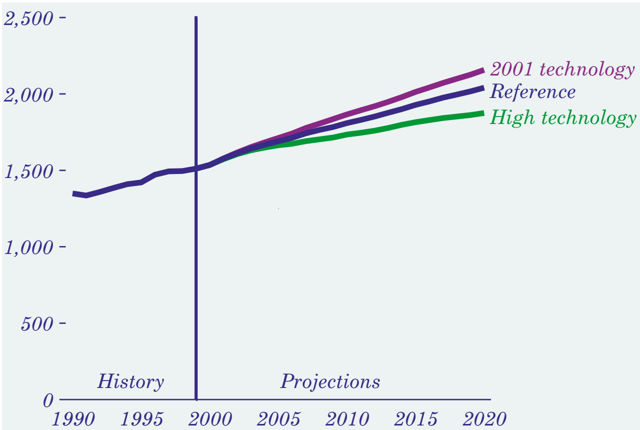

In the high technology case, about 46 percent, or 77 million metric tons carbon equivalent, of the reduction in expected carbon dioxide emissions compared to the reference case results from shifts to more efficient or alternative-fuel vehicles in the transportation sector. An additional 36 percent of the estimated reduction, or 60 million metric tons carbon equivalent, results from lower projections for electricity demand and generation.

## *International Negotiations on Greenhouse Gas Reductions*

### *The Framework Convention on Climate Change*

As a result of increasing warnings by members of the climatological and scientific community about the

*Figure 36. Projected U.S. carbon dioxide emissions in three technology cases, 1990-2020 (million metric tons carbon equivalent)*




possible harmful effects of rising greenhouse gas concentrations in the Earth's atmosphere, the Intergovernmental Panel on Climate Change was established by the World Meteorological Organization and the United Nations Environment Programme in 1988 to assess the available scientific, technical, and socioeconomic information in the field of climate change. A series of international conferences followed, and in 1990 the United Nations established the Intergovernmental Negotiating Committee for a Framework Convention on Climate Change. After a series of negotiating sessions, the text of the Framework Convention on Climate Change was adopted at the United Nations on May 9, 1992, and opened for signature at Rio de Janeiro on June 4, 1992.

The objective of the Framework Convention was to ". . . achieve . . . stabilization of the greenhouse gas concentrations in the atmosphere at a level that would prevent dangerous anthropogenic interference with the climate system." All signatories agreed to implement measures to mitigate climate change and prepare periodic emissions inventories. In addition, the developed country signatories agreed to adopt national policies with a goal of returning anthropogenic emissions of greenhouse gases to 1990 levels. The Convention excludes chlorofluorocarbons and hydrochlorofluorocarbons, which are controlled by the 1987 Montreal Protocol on Substances that Deplete the Ozone Layer.

In response to the Framework Convention, the United States issued the Climate Change Action Plan (CCAP) [*62*], published in October 1993, which consists of a series of 44 actions to reduce greenhouse gas emissions. The actions include voluntary programs, industry partnerships, government incentives, research and development, regulatory programs including energy efficiency standards, and forestry actions. Greenhouse gases affected by the CCAP actions include carbon dioxide, methane, nitrous oxide, hydrofluorocarbons, and perfluorocarbons. At the time CCAP was developed, the Administration estimated that the actions it enumerated would reduce total net emissions [*63*] of these greenhouse gases in the United States to 1990 levels by 2000. Although CCAP no longer stands as a unified program, many of its individual programs remain in effect.

### *The Conference of the Parties and the Kyoto Protocol*

The Framework Convention established the Conference of the Parties to "review the implementation of the Convention and . . . make, within its mandate, the decisions necessary to promote the effective implementation." Moving beyond the 2000 target in the Convention, the first Conference of the Parties met in Berlin in 1995 and issued the Berlin mandate, an agreement to "begin a process to enable it to take appropriate action for the period beyond 2000." The second Conference of the Parties, held in Geneva in July 1996, called for negotiations on quantified limitations and reductions of greenhouse gas emissions and policies and measures for the third Conference of the Parties. From December 1 through 11, 1997, representatives from more than 160 countries met in Kyoto, Japan, at the third session of the Conference of the Parties. In the resulting Kyoto Protocol to the Framework Convention, targets for greenhouse gas emissions were established for the developed nations—the Annex I countries—relative to their emissions levels in 1990 [*64*].

The targets are to be achieved, on average, from 2008 through 2012, the first commitment period in the Protocol. The overall emissions reduction target for the Annex I countries is 5.2 percent below 1990 levels. Relative to 1990, the individual targets range from an 8-percent reduction for the European Union (EU) to a 10-percent increase for Iceland. The reduction target for the United States is 7 percent below 1990 levels. Non-Annex I countries have no targets under the Protocol, although the Protocol reaffirms the commitments of the Framework Convention by all parties to formulate and implement climate change mitigation and adaptation programs.

The Protocol was opened for signature on March 16, 1998, for a 1-year period. It will enter into force 90 days after 55 Parties, including Annex I countries accounting for at least 55 percent of the 1990 carbon dioxide emissions from Annex I nations, have deposited their instruments of ratification, acceptance, approval, or accession. By March 15, 1999, 84 countries had signed the Protocol, including all but two of the Annex I countries, Hungary and Iceland. To date, 30 countries [*65*] have ratified or acceded to the Protocol, but no Annex I nations have done so.

Energy use is a natural focus of greenhouse gas reductions. In 1990, total greenhouse gas emissions in the United States were 1,655 million metric tons carbon equivalent, of which carbon dioxide emissions from the combustion of energy accounted for 1,349 million metric tons carbon equivalent, or 82 percent [*66*]. By 1999, total U.S. greenhouse gas emissions had risen to 1,833 million metric tons carbon equivalent, with 1,511 million metric tons carbon equivalent (82 percent) from energy combustion. Because energy-related carbon dioxide emissions constitute such a large percentage of total greenhouse gas emissions, any action or policy to reduce emissions will affect U.S. energy markets.

The Kyoto Protocol includes a number of flexibility measures for compliance. Reductions in other greenhouse gases—methane, nitrous oxide, hydrofluorocarbons, perfluorocarbons, and sulfur hexafluoride—can offset carbon dioxide emissions [*67*]. "Sinks" that absorb carbon dioxide—forests, other vegetation, and soils—may also be used to offset emissions, but specific guidelines and rules for the accounting of land-use and forestry activities remain to be resolved by the Conference of the Parties.

Emissions trading among the Annex I countries is also permitted under the Protocol, and groups of Annex I countries may jointly meet the total commitment of all the member nations either by allocating a share of the total reduction to each member or by trading emissions rights. Joint implementation projects are also allowed among the Annex I countries, allowing a nation to take emissions credits for projects that reduce emissions or enhance sinks in other Annex I countries. However, it is indicated in the Protocol that trading and joint implementation are supplemental to domestic actions. The Protocol also establishes a Clean Development Mechanism (CDM), a program under which Annex I countries can earn credits for projects that reduce emissions in non-Annex I countries if the projects lead to measurable, long-term emissions benefits.

The targets specified in the Protocol can be achieved on average over the first commitment period of 2008 to 2012 rather than in each individual year. No targets are established for periods after 2012, although the Conference of the Parties will initiate consideration of future commitments at least 7 years before the end of the first commitment period. Banking— carrying over emissions reductions that go beyond the target from one commitment period to some subsequent commitment period—is allowed. The Protocol indicates that each Annex I country must have made demonstrable progress in achieving its commitments by 2005.

At the fourth session of the Conference of the Parties in Buenos Aires, in November 1998, a plan of action was adopted to finalize a number of the implementation issues at the sixth Conference of the Parties (COP 6), held November 13 through 24, 2000, at The Hague, the Netherlands. Negotiations at the fifth Conference of the Parties in Bonn, Germany, from October 25 through November 5, 1999, focused on developing rules and guidelines for emissions trading, joint implementation, and CDM, negotiating the definition and use of forestry activities and additional sinks, and understanding the basics of a compliance system, with an effort to complete this work at COP 6 [*68*].

Negotiations were held before COP 6 on a range of technical issues, including emissions reporting and review, communications by non-Annex I countries, technology transfer, and assessments of capacity needs for developing countries and countries with economies in transition. The United States affirmed its support for the inclusion of a wide range of land and forest management activities under the Protocol, and for an accounting system that would include the total net impact of land management on carbon stocks [*69*]. The goals of COP 6 included developing the concepts in the Protocol in sufficient detail that it could be ratified by enough Annex I countries to be put into force, and encouraging significant action by the non-Annex I countries to meet the objectives of the Framework Convention [*70*].

### *EIA's Analyses of Emissions Reductions*

In 1998, at the request of the U.S. House of Representatives Committee on Science, EIA analyzed the likely impacts of the Kyoto Protocol on U.S. energy prices, energy use, and the economy in the 2008 to 2012 period. The analysis was published in *Impacts of the Kyoto Protocol on U.S. Energy Markets and Economic Activity* [*71*], with an accompanying briefing report, *What Does the Kyoto Protocol Mean to U.S. Energy Markets and the U.S. Economy?* [*72*].

In 1999, the Committee on Science made an additional request for EIA to analyze the impacts of an earlier, phased-in start date for U.S. carbon dioxide emissions reductions. Earlier carbon dioxide reductions could lead to the purchase of more efficient or less carbon-dioxide-intensive equipment at an earlier date, making it easier and less expensive to meet greenhouse gas emissions targets. The resulting analysis, *Analysis of the Impacts of an Early Start for Compliance with the Kyoto Protocol*, was published in July 1999 [*73*].

In both 1999 and 2000, EIA received requests from the U.S. House of Representatives for analyses of the Administration's Climate Change Technology Initiative (CCTI)—from the Committee on Science in 1999 and from the Committee on Government Reform, Subcommittee on National Economic Growth, Natural Resources, and Regulatory Affairs in 2000. The two resulting studies examined the impacts of the fiscal year 2000 and 2001 budget requests for tax incentives, research and development, and other spending in CCTI, primarily focusing on the tax incentives. Both studies analyzed the potential of CCTI to reduce energy consumption and carbon dioxide emissions. The results were published in *Analysis of the Climate Change Technology Initiative* (April 1999), and *Analysis of the Climate Change Technology Initiative: Fiscal Year 2001* (April 2000) [*74*].

Most recently, EIA was requested by the Committee on Government Reform, Subcommittee on National Economic Growth, Natural Resources, and Regulatory Affairs to undertake a two-part study on reducing emissions from electricity generating plants. The first report, scheduled for release in December 2000, will analyze the potential costs of various strategies to achieve simultaneous reductions in emissions of sulfur dioxide, nitrogen oxide, and carbon dioxide by electricity generators. The strategies are based on bills that have been proposed in the House of Representatives and the Senate. The second report, to be released early in 2001, will analyze the costs of reducing mercury emissions and the impacts of renewable portfolio standards. The two reports, taken together, will give a sense as to the costs of reducing multiple emissions and the potential cost savings from doing so in a coordinated fashion.